Status Report on the Gas Potential From Devonian Shales of the Appalachian Basin

November 1977

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Status Report on the

Gas Potential From Devonian Shales of the Appalachian Basin

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Congress of the United States
OFFICE OF TECHNOLOGY ASSESSMENT
WASHINGTON, D.C. 20510

November 23, 1977

The Honorable Ted Stevens
Technology Assessment Board
Off ice of Technology Assessment
United States Senate
Washington, D.C. 20510

Dear Senator Stevens:

On behalf of the Board of the Office of Technology Assessment. I am pleased to forward the results of the assessment you requested of the potential of enhanced recovery of oil and Devonian gas in the United States.

This report, A Status Report on the Potential for Gas Production From the Devonian Shales of the Appalachian Basin, is the first to be completed. Work on the enhanced oil recovery report will be completed soon.

These assessments will provide additional perspective on future U.S. energy supplies and we hope that they will be helpful as the Congress continues its review of national energy policy.

Sincerely,

Edward M Kennedy

EDWARD M. KENNEDY
Chairman

Sincerely,

Larry Winn Jr.

LARRY WINN, JR.
Vice Chairman

Enclosure

Foreword

This report is an analysis by the Office of Technology Assessment of the potential for producing gas from the Devonian shales of the Appalachian Basin. It was prepared in response to a request from Senator Ted Stevens, a member of the Technology Assessment Board.

Few data are now available on the distribution and physical and chemical characteristics of the Devonian shales of the Appalachian Basin. A comprehensive assessment must therefore await the results of extensive drilling throughout the region. In the meantime, however, this report, which is based on plausible economic, geologic, and technological assumptions, provides reasonable estimates of the recoverable gas in the Basin.

The Devonian Brown shales of the Appalachian Basin, so-called because they accumulated during the Devonian age, have the potential of contributing significantly to the U.S. natural gas supply. It can reasonably be assumed that these shales contain as much as 15 to 25 trillion cubic feet of readily recoverable reserves that could be produced economically over a 20-year period at prices of $2.00 to $3.00 per thousand cubic feet. These reserves could ultimately support a production rate of about 1 trillion cubic feet of natural gas per year, which is about 5 percent of the current level of domestic gas production. Such a production rate is likely to require extensive drilling (on the order of 69,000 wells), a considerable expansion of the gas pipeline collecting network and, therefore, up to 20 years to achieve. These estimates are less optimistic than some that have been reported by the Energy Research and Development Administration and others, but they are generally consistent with current work at the U.S. Geological Survey.

This report is another in the series of energy assessments that are being provided to the Congress for its consideration in the development of national energy policy.

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NOTE: The Advisory Panel provided advice, critique, and assistance throughout this assessment, for which the OTA staff is deeply grateful. The Advisory Panel, however, does not necessarily approve, disapprove, or endorse all aspects of this report. OTA assumes full responsibility for the report and the accuracy of its content.

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1. Executive Summary

1. Executive Summary

Declining domestic reserves of natural gas and a widening gap between domestic production and demand has led to new interest in several unconventional or exotic sources of the fuel. These include the geopressurized zones off the gulf coast, the tight sands of the Western Basin, coal seams of the Eastern United States, and Devonian shales of the Appalachian Basin.

This report examines the potential for producing gas from one of these sources—the Devonian shales—Using existing technology under a variety of economic assumptions.

Findings

A major finding of the analysis is that Devonian shale, unlike the other exotic sources, can be tapped for natural gas without the development of completely new production equipment or techniques.

A second finding is that the so-called "Brown" Devonian shales of the Basin could yield between 15 trillion cubic feet* (Tcf) and 25 Tcf of natural gas during the first 15 to 20 years of production. Over an additional 10 to 30 years of production, the Brown shale could yield half again as much, for a total production of about 23 Tcf to about 38 Tcf.

A third finding is that because Brown shale deposits are distributed over extensive areas, it may take as many as 20 years to drill all of the wells and complete the pipeline system that would be required to produce as much as 1.0 Tcf of natural gas per year.

The findings are based on the following assumptions:

- there will be no significant changes in real costs of drilling, stimulating the flow of gas or production;
- the economic and production characteristics of three regions analyzed in the assessment represent the more promising sources of natural gas from Devonian shale;
- wellhead prices for natural gas will be in the range of $2.00 to $3.00 per thousand cubic feet (Mcf);
- current tax treatment of income from natural gas production will be continued; and
- approximately 10 percent of the Brown shale resource is of high enough quality to permit commercial development.

The Resource

The darker layers of shale of Devonian age, which are referred to throughout this report as Brown shale, are found below ground throughout the Appalachian Basin. The Brown shale can be reached by drill in southwestern Pennsylvania, southern New York, eastern Ohio, most of West Virginia, and eastern Kentucky. It also is exposed at the ground surface along the northern and western sides of the Basin.

The Brown shale is thickest and therefore more likely to yield commercial quantities of natural gas in the west-central region of the Basin. In that area, it comprises between 30 and 40 percent of

*Natural gas is measured in cubic feet: Mcf = thousand cubic feet, MMcf = million cubic feet, Bcf = billion cubic feet, Tcf = trillion cubic feet, the total mass of Devonian shale. To the west, the Brown shale becomes thinner and to the east it splits into separate beds that eventually disappear in a thick mass of coarser sediments. The Brown shale originally formed as a black mud, rich in organic matter, on the floor of a Devonian sea. Individual beds of Brown shale are up to 1,200 feet thick; maximum depth is about 12,000 feet.

The Brown shale consists of alternating paper-thin laminations of inorganic and organic matter. The inorganic layer consists of clay, quartz, and other common sedimentary minerals. The organic layer consists of extremely fine particles of coal-like material and of minute shreds of coalified woody matter. Thus the Brown shale is not an "oil shale" like the shales of Colorado and Wyoming but rather, it is coal-like.

Gas production from the shale is greatest from highly fractured zones. Evidence suggests that the gas that moves most readily in the Brown shale is in these fractures, and possibly in some of the coarser-grained laminations. The vast bulk of the gas is held in the shale mass itself, the "matrix," from which it will move into fractures and well bores at very slow rates, Initial production from Brown shale wells is relatively high, as free gas in fractures moves to the well bore, but the flow decreases steadily to that determined by the rate at which the gas in the shale matrix is released. Estimates of the total amount of gas in the Brown shale of the Appalachian Basin range up to many hundreds of Tcf.

Gas Potential

It appears that under plausible economic, geologic, and technological assumptions the Brown shale of the Appalachian Basin contains at least 15 to 25 Tcf of readily recoverable gas.[1] This is gas that would be producible in the first 15 to 20 years of life of typical Brown shale wells. Shale gas production has a slow flow rate over a long period of time, so ultimate recoverable reserves over the 30- to 50-year expected life of production could be 40 to 50 percent greater than the 15 to 25 Tcf estimate. The recoverable gas potential of the Brown shale depends on the (1) wellhead price and production costs, (2) extent of the Brown shale resource, and (3) the relative amounts of high-, medium-, and low-grade gas-producing brown shales.

The $1.42 to $3.00 per Mcf price assumptions (equivalent to oil at $6.90 to $14.50 per barrel) used in this study are consistent with general market conditions for both interstate and intrastate gas sales. The drilling, well completion, stimulation, and production cost estimates are based on actual operating experience in 1976. All cost and price calculations are in constant 1976 dollars.

There is a good deal of evidence that in a large oil and gas area the discovery wells tend to be drilled into the better structures and subsequent drilling defines the geologic and economic limits of the resource base. In a marginal resource base such as the Brown shale (where the extensive geologic existence of gas-bearing reservoirs is not in doubt), the definition of "the better structures" includes the location relative to existing production and pipelines. Except in southeastern Kentucky, the Brown shale has only recently become a primary target of drilling operations. Even if the current areas of Brown shale development activity were initially byproducts of other activity, the "better" Brown shale prospects are probably already developed. But "better" as used here includes the factor of location relative to existing gathering lines.

There may be additional areas which are as geologically promising as the localities examined in this study. These other areas, although more remote relative to existing pipelines, probably

[1] Readily recoverable reserves" is not a category in either the American Gas Association or U.S. Geological Survey nomenclature. In the present context, "readily recoverable reserves" are resources which can be converted to proved reserves and actually produced in a 15- to 20-year time frame.

become economically feasible at the $2.00 to $3.00 per Mcf price levels.

if higher-quality, gas-productive Brown shale accounts for as much as 10 percent of the total estimated extent of the shale (the currently producing area is less than 5 percent of the 163,000-square-mile extent of the Appalachian Basin), then a conservative estimate of the readily recoverable gas is approximately 15 to 25 Tcf. If there are 15 to 25 Tcf of readily recoverable gas, then it is possible that shale gas production in Ohio, West Virginia, New York, Kentucky, Tennessee, and Pennsylvania could account for as much as 1.0 Tcf per year in the future.

The estimates presented in this report are based on the analysis of 490 producing wells in three localities. These 490 wells were drilled by a large number of operators with different financial situations and technical capabilities. Data from a smaller number of wells drilled by a single operator exhibit higher production than the 490 wells. If the production from these single-operator wells is representative of a significant portion of the Brown shale of the Appalachian Basin, the Brown shale might contain more than 15 to 25 Tcf of readily recoverable gas and a production capability of greater than 1.0 Tcf per year. This greater potential could result from either or both (1) greater average productivity per well, or (2) a larger resource base which would permit a greater number of wells of average productivity. However, even under an optimal combination of circumstances (1 5-percent higher average production per well and a 50-percent increase in the areal extent of the quality shale resource), only about 30 to 35 Tcf of readily recoverable reserves would be producible over *15* to 20 years. Under these optimal conditions, annual shale gas production from the Appalachian Basin might approach 1.5 to 2.0 Tcf.

production of gas from the Brown shale is likely to be scattered over extensive areas, thus resulting in a relatively slow pace of development because of the need to build a pipeline gathering system. This suggests that the economically feasible expansion of the gas pipeline network required to collect new gas production will be on an incremental basis. The location of individual wells relative to potential pipeline connections (in addition to geologic promise) will continue to be an important determinant of the economic quality of Brown shale drilling prospects. Since Brown shale gas production is relatively well intensive and is likely to be scattered over an extensive area, it is prudent to presume that Brown shale gas development will proceed at a gradual pace, probably requiring at least 20 years to reach a 1.0 Tcf annual production level (about 69,000 wells in the Brown shale will be needed to produce 1.0 Tcf per year). If improvements in drilling or stimulation technology are achieved and economic incentives provided, the time necessary for the development of the gas potential of the Brown shale might be reduced. Therefore, the Congress may wish to consider the desirability of some publicly supported research and development activity directed toward improvements in Brown shale drilling and stimulation technology.

The potential impact of either (1) dramatically better technology, or (2) improvements in economic incentives beyond those examined here must be considered with caution. If economic incentives were twice as good as those considered in this study, or if drilling and stimulation technology were to improve so that these operations would cost only half as much as they now do, it is unlikely that twice as great a quantity of reserves would become economically feasible. This is because additional development efforts, which such economic or technological improvements would induce, would be pressing further and further into the poorer sites and geologic prospects.

Policy Options To Encourage Shale Gas Production

Policy options available to encourage production of gas from the Brown shale fall into four generic categories. These categories are:

- price incentives,
- tax policies,
- research and development funding, and
- information collection and dissemination.

Price Policies

Brown shale natural gas resource development is sensitive to price. The price of Brown shale gas sold in interstate commerce is currently restricted by Federal Power Commission (FPC) ceiling price regulations. There are three basic price strategies with respect to shale gas which could be pursued. These are:

- exempt shale gas from FPC price control or establish higher prices for gas from the Brown shale;
- deregulate the wellhead price of all new natural gas supplies; or
- take no action.

A policy which permits higher prices or exempts Brown shale ‘gas from FPC control would be analogous to a proposed policy that would permit the free market price for oil produced by enhanced recovery techniques. The qualification for gas from the Brown shale might be based on (1) geologic identification of the Brown shale as the source of gas, (2) regional specification, (3) production rate limitations, or (4) some combination of these factors.

Brown shale gas production is often commingled with production from other geologic zones. Therefore, a precise identification of gas production from the Brown shale could be extremely difficult.

Similar-appearing, gas-productive brown and black shales of differing geologic ages extend throughout many portions of the United States in addition to the Appalachian Plateaus, and a regional specification restricted to the Appalachian Plateaus might therefore omit substantial shale gas resource potential. Production rate limitations for eligibility for exemption from price regulation might be more manageable, and also would apply to gas production from tight formations in other parts of the country. Definition and administration of a multitiered pricing system for gas from the Brown shale could become arbitrary, complex, and cumbersome.

Deregulation of the wellhead price of all new gas supplies would include prospective additions to the U.S. natural gas supply from the Brown shale of the Appalachian Basin. Such a strategy would create price incentives in the range of $2.00 to $3.00 per Mcf, on which conclusions presented in this report are based. Such price incentives might provide the stimulus necessary for an extensive testing of the economic feasibility of Brown shale gas production. If 10 percent of the 163,000-square-mile extent of the Brown shale is medium- to high-quality gas-productive shale, an expansion in drilling efforts could result in production of approximately 1.0 Tcf per year of gas from the Brown shale of the Appalachian Basin within the next 20 years.

If Congress takes no action on prices, existing prices would be the only incentive to encourage gas production from the Brown shale. Current maximum interstate gas prices encourage gas production with existing technology from only the high-quality Brown shale areas. Therefore, continuation of present gas pricing policy could result in foregoing substantial additions to the U.S. natural gas supply which may be available from the Brown shale of the Appalachian Basin.

Tax Policies

The tax policies available to Congress to encourage Brown shale gas production include:

- restoration of the general 22-percent depletion allowance;
- definition of Brown shale gas production as enhanced recovery so as to maintain the depletion allowance for small producers;
- retention of expensing of intangible drilling costs as a tax option; and

- creation of a 1 O-percent investment tax credit for gas production from the Brown shale.

The analysis reported here indicates that a 10-percent investment tax credit has little effect on shale gas production. Areas of lower resource quality did not become economically feasible for shale gas production when a 10-percent investment tax credit was incorporated into the analysis. However, the addition of a 22-percent depletion allowance increased the after-tax, net-present value of shale wells and made certain production methods economically feasible in shales of lower quality. Basically, a 22-percent depletion allowance has about the same positive effect on the economics of shale gas production as a $.50 per Mcf increase in the wellhead price of shale gas.

Research and Development

There are several areas in which research and development with special relevance to the Brown shale of the Appalachian Basin might be fruitfully pursued. These include:

- defining resource characteristics,
- development of drilling techniques and equipment, and
- improvement of logging and stimulation techniques.

Even though about 10,000 wells already produce gas from the Brown shale of the Appalachian Basin, few quantitative data are available to adequately characterize the resource potential of the entire 163,000-square-mile Appalachian Plateaus. Until the Brown shale resource is adequately characterized, specific targets for technology development are not possible. A systematic coordinated inventory of Brown shale should be one of the first steps in developing the gas potential of the Brown shale sequence.

The most common techniques used to characterize the Brown shale are those developed for use in traditional oil and gas reservoirs, Development of special drilling techniques and equipment specifically for use in the Brown shale could expedite the development of its gas potential. Because of the importance of well stimulation in the production of gas from the Brown shale, improvement in the effectiveness and reductions in costs of stimulation techniques could make gas production from Brown shale more economically attractive. Price incentives can be expected to induce some private activity in these research and development areas. However, because much drilling, well stimulation, and production will be done by operators who do not control large shares of Brown shale resources, it is unlikely that those operators will invest large amounts in aggressive research and development programs. Therefore, it may be prudent to commit public funds for research and development activity directed specifically toward improvements in shale drilling and stimulation technology.

Information Collection and Dissemination

Although the Devonian shale sequence is distributed over a wide geographic area, only a small portion of it has potential as a commercial source of gas. If the gas potential of the Brown shale is exploited, a large number of independent operators are likely to be drilling a large number of wells in many different locations on the Appalachian Plateaus. Under these conditions, particularly in the early years of the development effort, it might be desirable to fund publicly the collection, coordination, and dissemination of information and analyses detailing the results of actual operating experiences. This activity should be undertaken by a creditable public group so that the results are available to the public and private sectors alike. The information collection and dissemination efforts might initially include the public funding of conferences where research and development results and improved drilling and stimulation technologies are reported. If the Brown shale has a potential to produce 1.0 Tcf of gas per year, and economic incentives are provided, it is likely that private enterprise will assume necessary research and development efforts within a comparatively short period of time.

Conclusions

There are a number of policy options available which could encourage production of gas from the Brown shale of the Appalachian Basin. A significant and substantial policy option is to permit free-market prices for gas from Brown shale formations. Restoration of the 22-percent depletion allowance would have about the same effect as increasing the well head price of shale gas by $.50 per Mcf. Research and development efforts which characterize the Brown shale resource, decrease the cost of drilling and stimulation of wells, and increase the gas production from wells, could increase the economic attractiveness of producing gas from the Brown shale of the Appalachian Basin.

II. Introduction

II. Introduction

The Natural Gas Situation

Since *1970,* the United States has consumed natural gas faster than it has discovered new reserves (table 1 and figure 1). Annual production has declined steadily from a peak of 22.6 trillion cubic feet (Tcf) in 1973 to a 1976 level of 19.5 Tcf; the decline is projected to continue in the future unless new gas is discovered and added to the Nation's reserves (figure 2). Producers are currently delivering 20 percent less natural gas to interstate pipelines than is called for in firm contracts (table 2). The shortages of gas for industrial use are the most serious, but supplies for residences and small businesses have also been curtailed in some areas.

Three general changes in policy have been proposed by industry, Government, and independent analysts as ways to stem the decline in

Table 1
Proved Reserves of Natural Gas in the United States, 1959-76

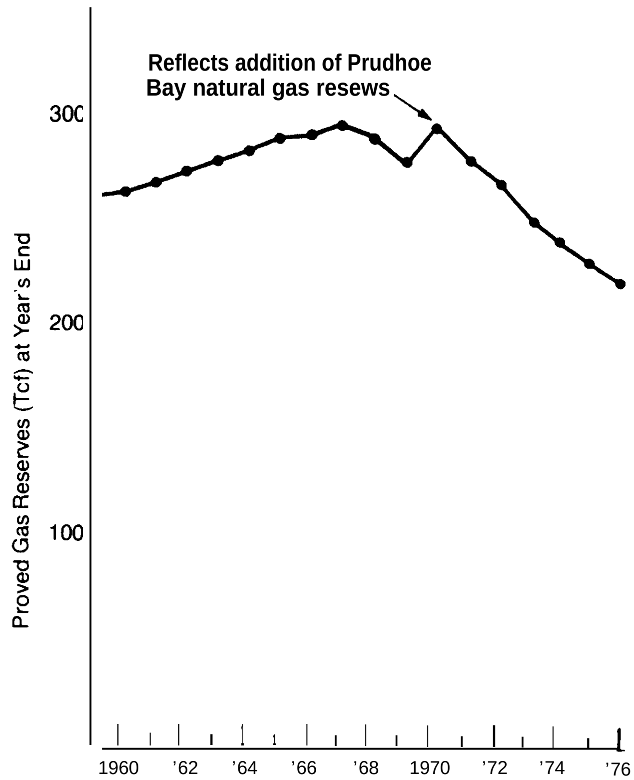
(Trillions of cubic feet; 14.73 PSIA at 60°F)

Year	Proved Reserves at Beginning of Year	Proved Reserves at End of Year	Net Change From Previous Year
1959	252,8	261.2	+8.4
1960. , ...	261.2	262.3	+ 1.1
1961. , ...	262.3	266.3	+4.0
1962	266.3	272.3	+ 6.0
1963 ..,	272.3	276.2	+ 3.9
1964	276.2	281.3	+ 5.1
1965	281.3	286.5	+ 5.2
1966	286.5	289.3	+ 2.8
1967	289.3	292.9	+ 3.6
1968, ...	292.9	287.4	-5.5
1969 ..., . .	287.4	275.1	-12.3
1970 .....,	275.1	290.8	+15.7
1971.	290.8	278.8	-12.0
1972	278.8	266.1	-12.7
1973	266.1	250.0	-16.1
1974	250.0	237.1	-12,9
1975	237.1	228.2	-8.9
1976	228.2	216.0	-12.2

Note: 1970 figures reflect **the addition** of Prudhoe **Bay, Alaska** reserves.

Source. Reserves of crude **oil, natural** gas liquids, **and natural** gas in **the United States and Canada** as of **December** 31, 1976 Joint publication by **the American** Gas Association, Americ**an Petroleum** Institute, **and Canadian Petroleum** Association Vol. **31, May 1977**

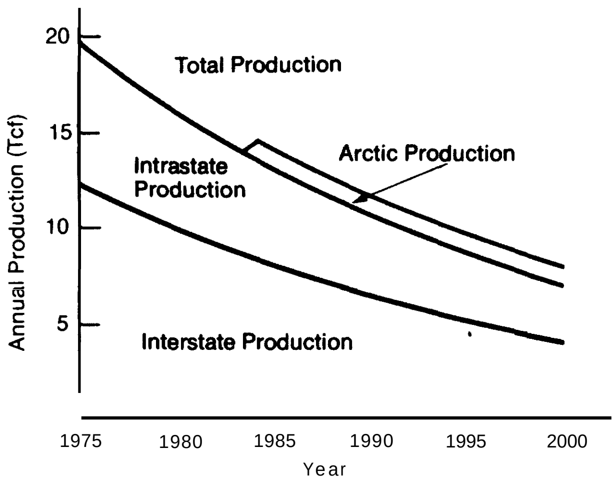
Figure 1. Proved Reserves of Natural Gas in the United States, 1959-76



Source" Reserves of crude 011 natural gas liquids. and natural gas in the United States and Canada as of December 31, 1976 Joint publication of the American Gas Association. American Petroleum Institute, and Canadian Petroleum Association Vol 31, May 1977

Figure 2. Projected U. S. Natural Gas Production, 1975-2000

(assuming 8.0 Tcf reserve additions per year)



Source Federal Power Commission.

Table 2
U.S. Production of Natural Gas and Curtailments of Firm Customers, 1959-76

Year	Production (Trillions of cubic feet)	Interstate Pipellne Curtailments (Trillions of cubic feet)
1959	12.4	-0-
1960 .., . . .	13.0	-0-
1961	13.4	-0-
1962 .., . . .	13.6	-0-
1963	14.6	-0-
1964, ...	15.4	-0-
1965	16.3	-0-
1966	17.5	-0-
1967	18.4	-0-
1968	19.4	-0-
1969	20.7	-0-
1970	22.0	0.0
1971	22.1	0.3
1972	22.5	0.7
1973	22.6	1.1
1974	21.3	1.7
1975	19.7	2.6
1976	19,5	4.0

Source: Federal Power Commission and American Gas Associa-tion.

production and narrow the gap between supply and demand for natural gas. They are:

1. Decontrol natural gas prices so that increased costs would encourage consumers to use less fuel and increased wellhead prices would encourage producers to intensify their efforts to locate new reserves.
2. Permit price increases under regulation to achieve some, but not all, of the stimulus of production that is anticipated as a result of deregulation.
3. Accelerate efforts to produce natural gas from unconventional geologic formations, such as the tight sands of the Western Basins, coal seams in the Eastern United States, geopressurized zones off the gulf coast, and Devonian shales of the Appalachian region of the Eastern United States.

This report examines the gas-productive potential of the last of these unconventional sources, the Devonian shales, which contain many hundreds of Tcf of natural gas, located in an area of the Nation where natural gas is in short supply. The report assesses the potential for producing natural gas from the Devonian shales of the Appalachian region and the impact on this production potential of various policy options available to Congress, Among all unconventional sources, the Devonian shales have the advantage of being productive, at least locally, in the Appalachian Basin without the development of completely new and novel techniques for gas recovery.

Ill. Regional Effects of Producing Gas From Devonian Shale

III. Regional Effects of Producing Gas From Devonian Shale

The regional effects of the production of gas from Devonian shale will depend largely on what happens to the price of natural gas. If the regulated price were allowed to move closer to the level that would be determined by prevailing market forces, there undoubtedly would be an increase in investment in new wells in the Devonian shale area. The same result would likely occur if controls on gas prices were eliminated.[1]

A significant addition to the available supply of natural gas might reduce upward pressure on gas prices. The regions that would probably benefit most from reduced pressure on gas prices are the New England, Middle Atlantic, East North Central, and South Atlantic States.[2] These are regions in which the price of natural gas has consistently been above the national average, and they include the major industrial States east of the Mississippi. Only four States in these regions—West Virginia, Virginia, Pennsylvania, and Illinois—are among the Nation's 20 top energy-producing States. The other 18, and Washington, D. C., import most or all of the coal, oil, or natural gas they consume.

States which have been hardest hit by the dramatic rise in energy prices since 1973 are those which are both heavily industrialized and largely or entirely dependent on outside sources for their energy supplies. These States were industrialized at a time when energy prices were low, relative to other prices, and when the costs of transporting or transmitting energy were also relatively low. Of even greater importance is the growing number of people who are unable to buy natural gas at any price. Some consumers would benefit greatly from an increase in the Nation's supply of natural gas, even if this gas were available in the future only at substantially higher prices than those that have prevailed up to now.

In an economy in which prices are determined by market forces—whether the markets are considered to be "perfectly" competitive or not—there will always be some shifting about of industry. There have been major industrial migrations in the past, notably a shift of much of the textile and garment industries from north to south. These and other industrial migrations of the past have been the result of interregional labor cost differentials. Wage differentials have been reduced in recent years, and as the importance of labor costs as locational determinants have diminished, other costs which vary over space have become more important.

The cost of energy is likely to become an increasingly important locational determinant for a fairly wide range of industrial activities, but equally important—and in some cases more important—will be energy *availability.* Industrialists in relatively energy-intensive activities—such as those producing various chemical, plastic, rubber, and glass products—might be willing to relocate, or at least to expand, in areas with known reserves of natural gas. Indeed, one characteristic of Devonian shale gas wells—their long productive lives—could be considered a major advantage by manufacturers anxious to avoid supply interruptions over a long period of time. Most consumers of natural gas, including industrial consumers, buy their gas from a utility. But in an era of supply uncertainty, however, with strong inflationary pressures which will guarantee rising gas prices, there may be a growing incentive for industrial establishments to own their own gas wells and reserves. The availability of natural gas could make the Devonian shale areas highly attractive locations for energy-intensive activities.

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[1] See A V. Kneese, "Natural Resources Policy, 1976-1986," in *U.S Economic Growth from 7976 to 1986: Prospects, Problems, and Patterns, Vol* 4, Resources and Energy, Congress of the United States., Joint Economic Committee p. 139, Nov. 16, 1976.

[2] The States Included in these regions are: *New* England: Maine, Massachusetts, Connecticut, Vermont, New Hampshire, and Rhode Island; *Middle Atlantic:* New York, New Jersey, and Pennsylvania; *East North* Central: Ohio, Indiana, Illinois, Michigan, and Wisconsin; *South Atlantic:* Delaware, Maryland (including D.C,), Virginia, West Virginia, the Carolinas, Georgia, and Florida.

IV. The Resource

IV. The Resource

Geographic Extent

Sedimentary rocks of the geological age known as Devonian are present in the Appalachian region from New York to Alabama, in an area of some 209,000 square miles. The region includes two geological provinces of unequal size. in the smaller of these, an eastern belt known as the Valley and Ridge province, all rocks have been so intensely folded and faulted that few geologists consider them important sources of oil or gas, although recent studies indicate that the southern part of the Valley and Ridge has considerable potential for gas production. In the larger area, the Appalachian Plateaus immediately to the west, the rocks are flat-lying or only gently folded. Furthermore, the upper part of the Devonian system of rocks in this province contains dark brown or black shale, rich in organic matter, that yields some natural gas at present and reportedly has the potential of yielding a great deal more. The area of the Appalachian plateaus is 163,000 square miles.[1] These shales are covered by younger rocks but can be readily reached by the drill, and are located in southwestern New York, western Pennsylvania, eastern Ohio, most of West Virginia, and eastern Kentucky (figure 3). In addition, Devonian dark brown or black shales outcrop at the surface or beneath a few feet of glacially deposited debris in western New York, in a belt extending from Cleveland southward through central Ohio, and in a series of disconnected outcrops in north-central Kentucky.

Terminology

The term Devonian *shales* refers to all the shale strata that lie beneath a widespread younger formation known as Berea sandstone and above an older limestone termed Onondaga or Corniferous. The shales are found in one-half dozen Appalachian States; similar strata are known in Indiana, Illinois, and Michigan. They occur in the subsurface, where they are encountered in wells, and at the surface, where they have been mapped and studied. Over time, they have acquired a variety of geographically based names: Chattanooga shale in the Appalachian States; Marcellus shale in New York; Ohio shale in Ohio; and New Albany shale in Kentucky and Indiana. In this report, these terms are considered to be synonymous.

The Devonian shales include strata that are gray, greenish gray, grayish brown, and deep brown to black. The deep brown to black shales contain much organic matter, and are locally productive of gas. In most reports, including this one, they are called Brown *shale.* It is important to keep in mind the distinction between the whole thickness of Devonian shales and those parts—the Brown shale—that are richer in organic matter and of greater interest as a source of gas.

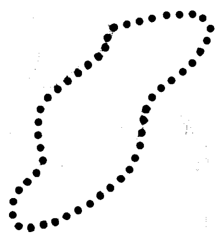
Origin

The position of the Devonian shales in the Appalachian Basin, and their relation to other rocks, can best be understood by looking briefly at their origin. To do this, it is necessary to erase one's mental image of present-day Appalachian geography for a moment and substitute Late Devonian geography of some 350 million years

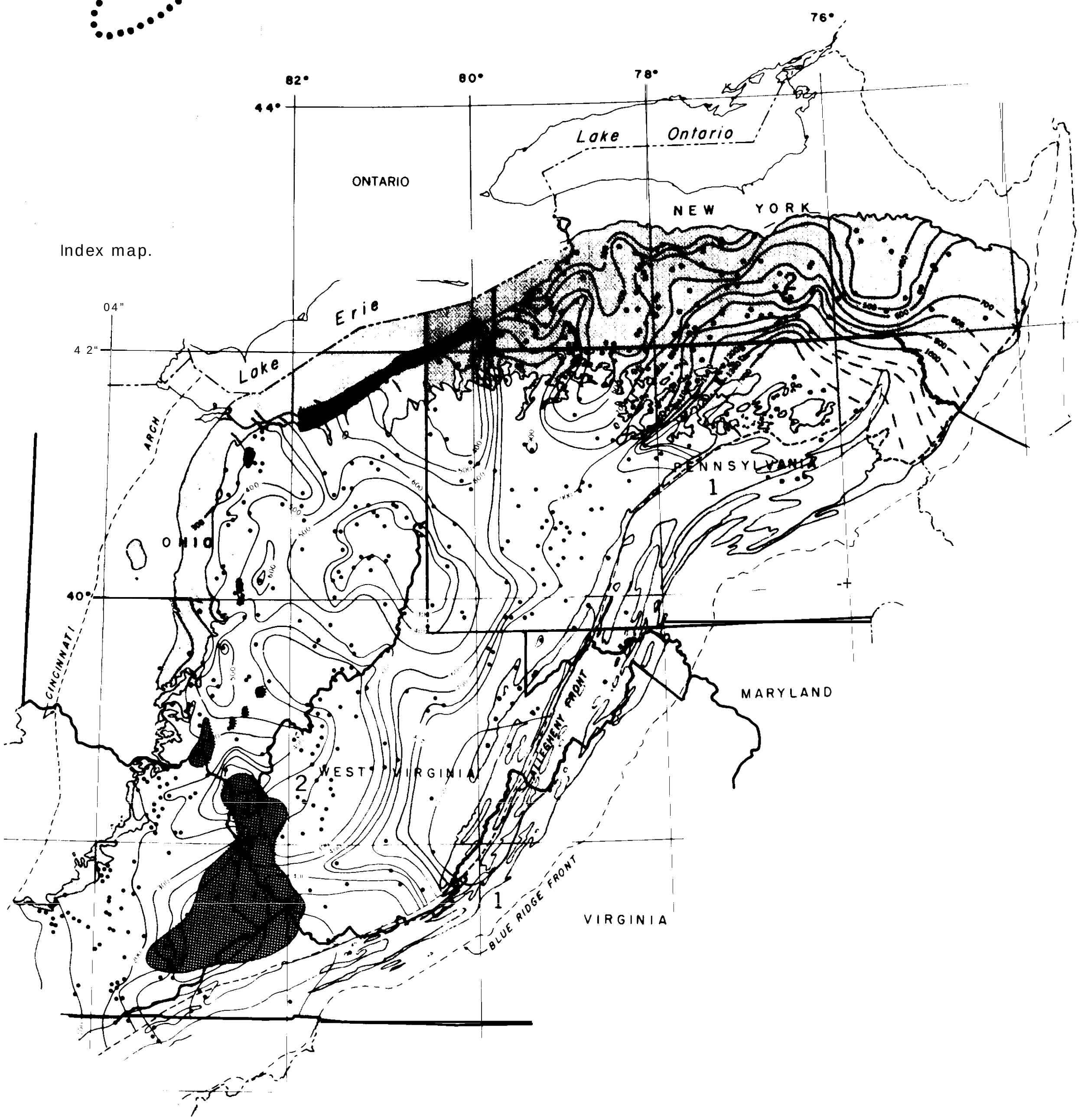
NOTE: All references to footnotes in this chapter appear on page 27.

Figure 3. The Appalachian Basin

In gray areas Devonian rock outcrop at the surface. Numbered lines give total thickness of all beds of Brown shale in the Devonian shale sequence. In cross-ruled areas gas has been or is being produced from Brown shales. (From deWitt et al., 1976, U.S. Geol. Survey Map I-917 B)



Index map.



ago. To the east of the region shown in figure 3, in a position roughly parallel to that of the present-day coastline, was a lofty range of mountains. Erosion of these mountains produced immense volumes of mud, silt, and sand, which were carried westward by streams and deposited in a great compound delta, the Catskill Delta. The Delta was built out into a seaway that covered parts of what is now the Appalachian Basin. In this sea, black organic-rich muds accumulated. The Devonian shoreline was not fixed: at times the sea level rose and marine muds were spread across the seaward parts of the Delta; at other times deltaic sands and silts flooded westward into the seaway, displacing the shoreline far to the west. As a result of these fluctuating conditions, the Brown shale interfinger to the east with much thicker and coarser deltaic rocks (figure 4). To the west, the black-mud bottomed sea was at times restricted by a lowland area termed the Cincinnati arch, and at other times it flooded across this feature to merge with seas in the Michigan basin and the Illinois basin. Although Brown shale deposition of Late Devonian time was not restricted to the Appalachian Basin, this region appears to be most important from the viewpoint of potential gas supply. In the long stretch of geologic time since the Devonian period, both the deltaic rocks and the shales have been buried by younger sediments. Around their edges they have been partially uncovered by uplift and erosion, but they remain under cover of younger rocks in much of the Appalachian Basin.

Thickness

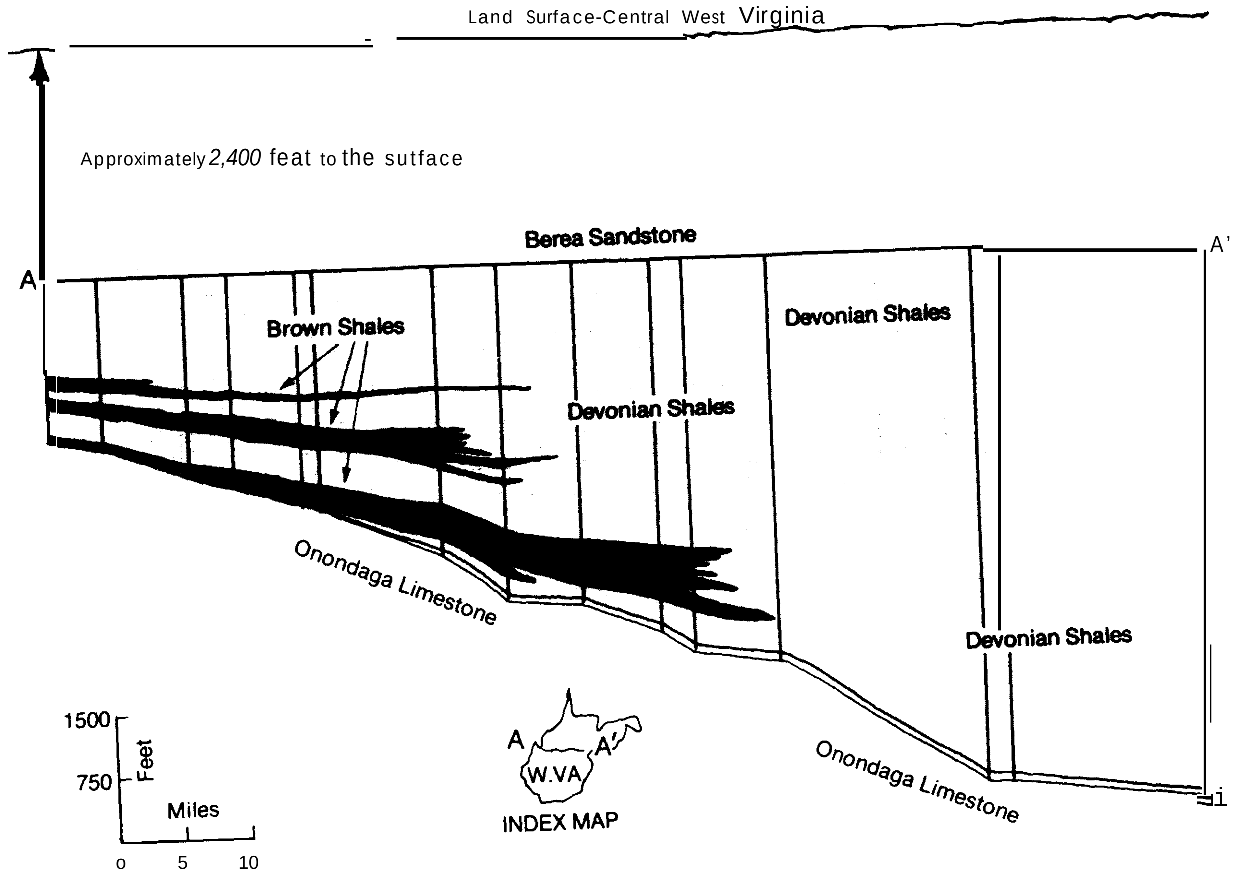
As indicated on figure 4, Upper Devonian rocks are a great wedge-shaped deposit, thin and shaly on the west and becoming thicker and more sandy toward the east. In south-central Kentucky, the section consists of about 20 feet of black shale.[2] This section thickens to about 400 feet at about the Kentucky-West Virginia line, and merges into a mass of siltstone, black silt, and sandstone some 7,OOO feet thick still farther east near the West Virginia-Virginia line. The shale section increases in thickness from less than **500** feet at the outcrop in southern Ohio to about **4,200** feet at the eastern edge of the State.[3]

Only a fraction of these thicknesses, however, represents Brown shale of potential interest as a commercial source of gas. A generalized log of the shale section penetrated by wells in eastern Kentucky, for example, shows an overall shale thickness of 677 feet, of which only an average thickness of 228 feet was Brown shaled[4]—One-third of the section. Of the eastern shales in general, "a 1 ,000-foot interval generally contains approximately 600 feet of light-colored shales and 400 feet of dark shales."[5] A general idea of Brown shale thicknesses in the Appalachian Basin is given by the contours on the map, figure 3. The thickness values on this map are stated to represent net thickness of Brown shale beds only;[6] the values are higher in the eastern part of the Basin than is suggested on the cross section, figure 4, because the geologists who compiled the map included more shale as Brown shale than those who made the cross section. Gas has been found through the entire Devonian shale, although the Brown shale has the highest concentration.

Attitude and Depth

In common with the other rocks in the Appalachian Basin, the Devonian shales have a gentle inclination, or dip, to the southeast. In eastern Kentucky, for example, they dip southeast at **30 to 50** feet per mile.[7] At the surface in central Ohio, the top of the shale section has an elevation of about 800 feet, but in southeastern Ohio this surface is some 1,400 feet below sea level. a This is a decline of 2,200 feet in 85 miles, or a dip of 26 feet per mile. It places the top of the shale section at a depth of about 2,000 feet in the Ohio River Valley between Ohio and West Virginia. A well in Carter County, northeastern Kentucky, near the common corner of Kentucky, West Virginia, and Ohio, reached the top of the shale section at 1,173 feet; in Pike County, easternmost Kentucky, the top of the shale lies at about 5,000 feet; the top of the shale is 12,000

Figure 4. West-East Cross Section Across Central **West Virginia**



Thickness of the total Devonian shales is about 2,000 feet at the west end of the section and 6,600 feet at the east end. Brown shales disappear into thicker strata toward the east. (Modified from Martin and Nuckols, 1976, ERDA Pub. MERC/SP-76/2. Fig. 4.)

feet below the surface of northeastern Pennsylvania. At no place in the Appalachian Basin is depth to the shale too great to be reached by the drill; indeed, many wells in parts of the Basin are drilled through the shale to deeper oil- or gas-bearing strata. There are minor variations in the southeastward dip, but these do not seem to have had a significant effect on accumulation of gas.

Composition

The basic unit of the Brown shale is a pair, or couplet, of microscopically thin layers: one rich in mineral matter and the other made up chiefly of organic matter. The fineness of the resulting lamination is hard to appreciate. Samples of Ohio shale taken from the outcrop in central Ohio were found to have as many as 230 laminae (couplets) in a 5-inch thickness.[9] References to "hairline bedding planes" and "paper-thin laminations" in published descriptions of the Brown shale from cores makes it clear that this characteristic persists in the subsurface as well.

Core samples of dark brown organic-rich shale from a producing gas well in the Cottageville Field, Jackson County, W.Va., were analyzed.[10] The inorganic part of the rock was found to consist chiefly of clay minerals, mainly illite, with the extremely fine grain size that is typical of clay (less than 0.004 mm). Silt-size grains of quartz and feldspar were present in amounts of 5 percent or more, and there were small amounts of calcite, dolomite, and pyrite. Another core from the same field analyzed at 60 percent clay minerals, 35 percent quartz and feldspar, and the remainder mostly pyrite and dolomite.[11] The grains of quartz and feldspar, mostly coarser than 0.004 mm, tend to occur in very thin laminae or lenses.

The organic fraction, reddish brown to chocolate brown in color, is made up of particles of coal-like material in the micron size range (0.001 mm). There are also minute shreds of coalified woody substance, and of spores and algae. The evidence from the organic material shows that it was mostly derived from plants, and this conclusion is supported by carbon-isotope studies. In the jargon of the coal petrologist the material consists largely of "humic degradation products," which were washed into the sea from lands to the east and possibly from lowlands on the Cincinnati arch. There must have been a "density stratification" in the waters of the Devonian Sea, a stagnant condition that inhibited vertical circulation and prevented the organic matter from being oxidized and destroyed as it accumulated on the bottom. A reasonable assumption is that each couplet of mineral-rich and organic-rich sediment may represent an annual accumulation. Organic matter typically makes up 10 to 20 percent of the rock by weight, or 40 to 60 percent by volume.[12]

It should be noted that the Brown shale is not "oil shale" like that of Colorado and Wyoming.[13] The organic matter is not the type of kerogen that characterizes such oil shales; rather, as noted above, the Brown shale are coal-like.

At outcrops, shales almost always split into thin flakes and plates parallel to the bedding. Another interesting aspect of the Brown shale is their content of uranium. Little is known of the reasons for this, except that the association of organic matter and uranium is evidently primary—the uranium was present at the time the muddy sediment was deposited, and was not introduced in later time.[14] The uranium content of the Brown shale, which ranges from 0.005 percent to slightly more than 0.007 percent, has not yet allowed them to be of use as a commercial source of uranium, although it is conceivable that they may be of such use in the future. The radioactivity of these shales, however, is a highly useful characteristic in the search for gas, as the radioactivity makes Brown shale readily recognizable on gamma-ray logs of drilled wells.

Fractures

A feature of the Devonian shales, which is of special significance in the gas-bearing Brown shale, is a system of near-vertical fractures (also known as joints). Most of these are only a fraction of a millimeter wide. In well cores, some fractures have been observed to be filled with brown crystalline dolomite, which helps make the fracture porous and permeable. Spacing of the fractures is variable, but they may occur close enough together so that two or more are often intersected in a 6-inch well bore. The fractures are not randomly oriented, but occur in "sets" that are alined in certain directions.

The relationship between fractures and gas production is well shown by cores taken from two wells in the Cottageville Field, Jackson County, W. Va.[15 16] The cores intersect numerous fractures and a study of the orientation of these fractures resulted in two important findings. First, the dominant direction of the fractures is North 40° to 50° East. This is the regional trend of the Appalachian Mountains (though the significance of the parallelism is not well understood); more practically, it is also the direction in which the most productive gas wells in the Cottageville Field are alined. This clearly suggests a relation between gas production and this set of fractures. Second, in the well from which the larger flow of gas comes, there is a wide variation in fracture alinement. Only 21 percent of the fractures are alined North 40° to 50° East; other preferred directions are slightly west of north, slightly east of north, and nearly east-west. parts of the core from this well are "completely shattered" by fractures, and the well had a natural flow of more than 1 million cubic feet (MMcf) of gas per day. The core from the second well showed few fractures, and the well had no open flow at all. The conclusion seems clear that here, as elsewhere in the Appalachian Basin, gas production from the Brown shale is controlled largely by fractures, with the production rate dependent on the number, length, openness, and direction of these fractures.17

Although mapping of fracture patterns and intersections may well be the best guide to gas accumulation, mapping is a very difficult task. The cause of fracturing is not well understood, and at least nine theories have been suggested,[18] The fracture systems may be related, for example, to the deformation that produced the Appalachian Mountains; to settling above deep-lying faults, thousands of feet below the Devonian shales (figure 5); or to major zones of fracturing ("lineaments"), scores or even hundreds of miles long, that are known or suspected to exist in the region. Until the origin is known, a rational search for fracture-controlled gas accumulations will be difficult. A few fractures extend upward through overlying rocks and reach the surface, and their patterns can be detected by remote-sensing techniques (LANDSAT imagery). This is probably the best current approach to the problem.

Natural Gas in the Brown Shale

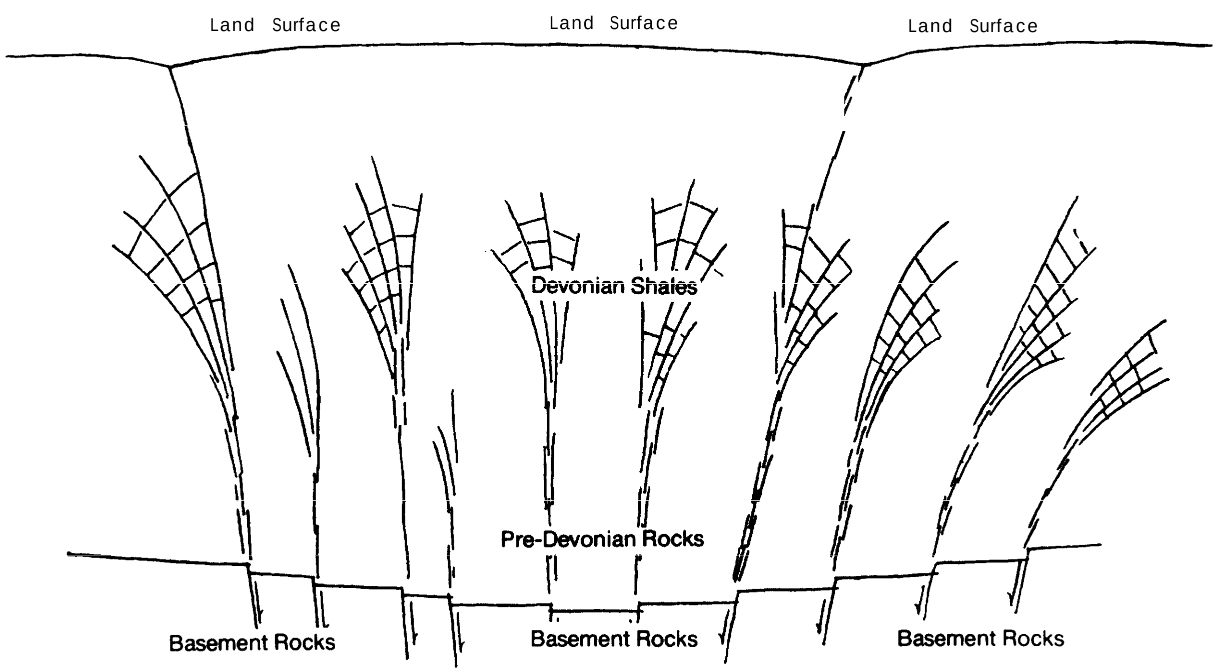
Although it has been known for more than 150 years that shallow wells drilled into the Devonian shales along their belt of outcrop would yield natural gas, the Brown shale was not generally considered a primary objective in exploration for natural gas until recently. In most parts of the Appalachian Basin, wells were drilled to deeper, more promising formations. If those failed to produce, the wells were "plugged back" to the Brown shale and attempts were made to stimulate enough gas from the formation to make a productive well,[19]

Drilling for gas started in western New York as early as 1820, and moved westward along the south shore of Lake Erie across northwestern Pennsylvania and into Ohio as far as Cleveland.[20] Shallow wells in the Brown shale supplied Louisville, Ky., with gas in the 1880's.[21] Two facts about this early production stand out. First, the rate of gas production was low; only enough to supply a small local industry, or a small cluster of households for heating and cooking could be expected from a given well. Second, the wells were very long-lived. Two wells at Fredonia, N.Y.—one drilled in 1821 and the other in 1850—had a combined annual production of only 6 MMcf (16,400 cubic feet per day), but when plugged 60 years later they were still producing 6 MMcf per year.[22] It was clear from this early experience that there was gas in the shale, but that the shale would yield it only at a low rate over a long time period. Today we know that gas moves readily only in fractures, and perhaps along some of the more silty bedding surfaces. The vast bulk of the gas is held in the shale mass, or "matrix," from which it will move into fractures and well bores at very low rates and over long time periods.

Estimates of the total amount of gas in the Devonian shales of the Appalachian Basin range from a few Tcf to many hundreds of Tcf.[23] Although the magnitude of the total resource is not known, there can be no doubt that it is large enough to be of potential importance to the Eastern United States.

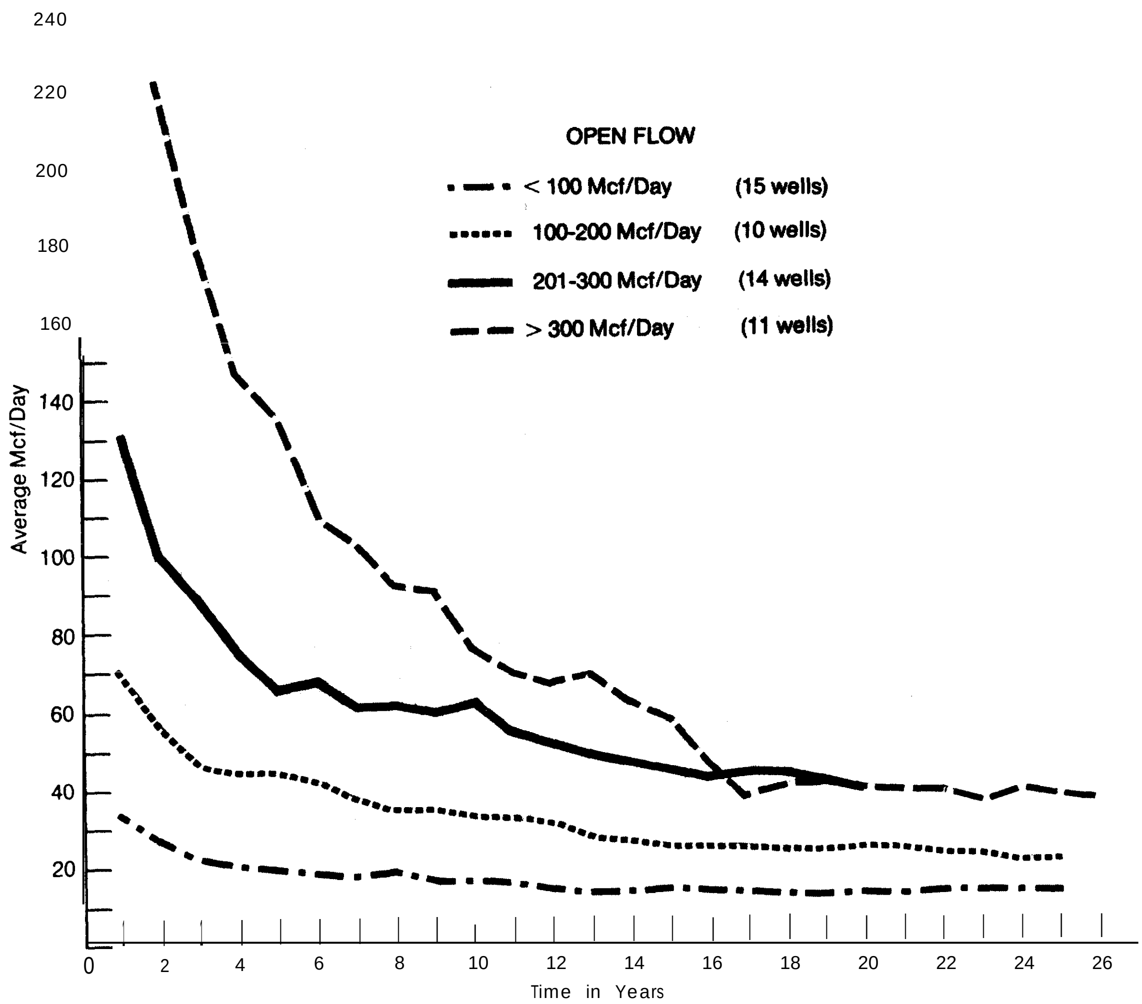
Present-day wells producing gas from the Brown shale recover only 2 to 10 percent of the original gas in place; 90 to 98 percent is left in the ground. The history of production in 50 Brown shale wells is indicated by the "decline curves" on figure **6.** Initial production is relatively high, as free gas in fractures moves to the well bore, but the flow decreases steadily to some value determined by the slow rate at which the gas in the shale matrix is released. Various techniques are being applied to the shale in an attempt to create artificial fractures extending outward from the well bore, thus potentially increasing the amount and rate of gas recovery by connecting more fracture systems to the well and exposing more surface area.

Figure 5. Model Showing Fractures Generated by Deep Seated Basement Faulting and Propagated Upwards Into the Devonian Shales



Source Overbey, 1976, Energy Research and Development Administration Pub. MERC/SP-76/2, Fig. 9

Figure 6. Averaged Production Decline Curves for 50 Devonian Shale Gas Wells



Lincoln, Mingo, and Wayne counties, West Virginia. Wells were metered on open flow after shooting or fracturing of the shale pay zone. Mcf = thousand cubic feet. (From Bagnall and Ryan, 1976, ERDA Pub. MERC/SP-76/2, Fig. 11; and W. D. Bagnall, personal communication.)

FOOTNOTES

[1]Wallace deWitt, Jr., et al., "Oil and Gas Data From Devonian and Silurian Rocks in the Appalachian Basin, " U.S. Gee!. Survey Map I-91 7 B, 1975.

[2]L.J. Provo, "Upper Devonian Black Shale—Worldwide Distribution and What It Means (abstract)," *Devonian Shale Produc-[fen and Potential,* ERDA Pub. MERC/SP-76/2, pp. 1-3, 1976,

[3]A. Janssens, "Potential Reserves of Natural Gas in the Ohio Shale in Ohio, " Ohio Geol. Survey, prepared at the request of the Joint Select Committee on Energy of the Ohio Legislature, p. 18, 1975.

[4]John Avila, "Devonian Shale as Source of Gas, " Natural Gas from *Unconventional Geologic Sources,* Nat. Acad. Sci. Pub. FE-2271 -1, pp. 73-85, 1976.

[5]P.J. Brown, "Energy From Shale—A Little Used Natural **Resource,** *Natural* **Gas** From *Unconventional Geologic* Sources, Nat. Acad. Sci. Pub. FE-2271 -1, pp 86-99, 1976.

[6]Wallace deWitt, Jr. personal communication, 1976.

[7]E. O. Ray, "Devonian Shale Development in Eastern Kentucky, " *Natural Gas From Unconventional Geologic* Sources, Nat. Acad. Sci. Pub. FE-2271 -1, pp. 100-112, 1976.

[8]A. Janssens, "Potential Reserves of Natural Gas in the Ohio Shale in Ohio, " Ohio Geol. Survey prepared at the request of the Joint Select Committee on Energy of the Ohio Legislature, p. 18, 1975.

[9]J. M. Schopf. Personal communication, 1976.

[10]D G. Patchen, and R.E. Larese, "Stratigraphy and Petrology of the Devonian 'Brown' Shale in West Virginia," Devon/an *Shale Production* and *Potential,* ERDA Pub. MERC/SP-76/2, pp. 4-19, 1976.

[11]P. Martin, and E.B. Nuckols, III, "Geology and Oil and Gas Occurrence in the Devonian Shales: Northern West Virginia," *Devonian Shale Production and Potential,* ERDA Pub, MERC/SP-76/2, pp. 20-40, 1976.

[12]J.M. Schopf, Personal communication, 1976.

[13]Maurice Deul, "Discussion, " Natural Gas from *Unconventional* **Geologic** Sources, Nat, Acad. Sci. Pub. FE-2271 -1, p. 123, 1976.

[14]L.C. Conant and V.C. Swanson, "Chattanooga Shale and Related Rocks of Central Tennessee and Nearby Areas, " U.S. Geological Survey, p. 357, 1961.

[15]P Martin and E.B. Nuckols, III, "Geology and Oil and Gas Occurrence in the Devonian Shales: Northern West Virginia, " *Devonian Shale Production and Potential,* ERDA Pub. MERC/SP-76/2, pp. 20-40, 1976.

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[17]W. D. Bagnall and W.M. Ryan, "The Geology, Reserves, and Production Characteristics of the Devonian Shale in Southwestern West Virginia, " Devon/an *Shale* Production *and* Potential, ERDA Pub. MERC/SP-76 /2, pp. 41-53, 1976.

[18]R.A. Hodgson, "Fracture Systems: Characteristics and Origin, " *Devonian Shale Production* and *Potential,* ERDA Pub. MERC/SP-76/2, pp. 54-74, 1976.

[19]John Avila, "Devonlan Shale as Source of Gas, " *Natural* Gas from *Unconventional Geologic* Sources, Nat. Acad. Sci. Pub. FE-2271 -1, pp. 73-85, 1976.

[20]Wallace deWitt, Jr., "Current Investigation of Devonian Shale by the U.S. Geological Survey, " *Natural Gas* from *Unconventional Geologic* Sources, Nat. Acad. Sci. Pub. FE-2271 -1, pp. 113-115, 1976.

[21]John Avila, "Devonian Shale as Source of Gas, " *Natural* Gas From Unconventional Geologic Sources, Nat. Acad. Sci. Pub. FE-2271-I pp. 73-85, 1976.

[22]Wallace deWitt, Jr., "Current Investigation of Devonian Shale by the U.S. Geological Survey, Natural *Gas* from *Unconventional Geologic* Sources, Nat. Acad. Sci. Pub. FE-2271-I , pp. 113-115, 1976.

[23]J.M. Foster, "A 'New' Gas Supply, " SPE-AIME #5451, 1975.

V. General Reservoir Characteristics

V. General Reservoir Characteristics

The reservoir characteristics of Brown shale are vastly different from those of typical oil- and gas-producing formations. Porosity indicates how much space exists in a particular formation where oil, gas, and/or water may be trapped. A commercially oil- or gas-productive sandstone or limestone reservoir has porosities in the range of 8 to 30 percent. By contrast, gas-producing Brown shales have porosities of 4 percent or less (table 3).

Much of the oil and gas in a formation may be unrecoverable because the pore structure is such that reasonable flow cannot take place. The ability of fluids and gases to flow through a particular formation, or permeate it, is called the permeability. The typical oil- and gas-producing formation has a permeability in the range of 5 to 2,000 millidarcies (mD). By contrast, most of the measured permeabilities of the Brown shale in productive areas are in the range of .001 to 2.0 mD (see table 3).

Since the characteristics of Brown shale reservoirs are so different from those of the usual oil and gas reservoir, evaluations of gas-production potential of the shales' by using conventional oil and gas techniques may result in erroneous conclusions. In the conventional oil and gas reservoir it is a simple matter to measure the percentage of the total reservoir that is occupied by oil, gas, and water. However, in dealing with the Brown shale it is very difficult to accurately determine these percentage saturations because the pores are so very small.

The manner in which natural gas is held in the Brown shale is a subject of considerable speculation. Some scientists believe that it is simply entrapped in extremely small pores. Others think the gas is adsorbed or molecularly held on the surface of the shale particles. ' Some of the natural gas may be dissolved in solid and liquid hydrocarbons in the reservoir. There is also some reason to believe that the gas may be in a liquid state in pores in the Brown shale. Available evidence[2] indicates that *virtually all of the Devonian shale contains gas* that is released or flows from the shale when the shale is placed in a relatively low-pressure atmosphere. However, current commercial production appears to enter the wells mainly from the Brown shale.

NOTE: All references to footnotes in this chapter appear on page 41.

Table 3
Comparison of Core Data for Brown Shale and Reservoir Roks From Other Gas Producing Areas

	Typical Permeability (millidarcies)	Typical Porosity (percent)	Typical Water Saturation (percent)
Hugoton - Anadarko Basin . .	20.	14	40
San Juan Basin'	1.	10	30
Permian Basin[a] . . .	15.	12	35
Brown Shale:			
Jackson County, W. Va.[b]			
(whole-core analysis). . . .	2.0	3.2	65
(conventional-core analysis)	0.1	3.0	70
Lincoln County, W. Va, '			
(whole-core analysis).	.004	0.6	0.0*
Perry County, Ky.[d]			
(whole-core analysts). . .	.3	4.0	35

"**Centrifuge measurement,** see text,

'**S Rudisell, N Beckner, and W.B Taylor (Phillips Petroleum Company), Personal communication, 197[J**

"**W. L. Pinnell (Consolidated Gas Supply Corp.) core data on Well #11440 and #12041 Personal communication), 1976**

[c]**Phase Report No. 1, Massive Hydraulic Fracturing of the Devo**nian Shale, **Columbia/ERDA Contract E (46-1) - 8014 Research Department, Columbia Gas System, October 1976,**

[d]**Final Report—Well No. 7239, Perry County, Ky,, ERDA-MERC, July 1975.**

All subsurface reservoirs initially exist at elevated pressures, regardless of whether they contain water, oil, or natural gas, J In conventional oil and gas reservoirs, a normal reservoir pressure (in pounds per square inch) is generally obtainable by multiplying the depth (in feet) below the surface of the ground by a factor of about *0.4.* For example, an oil and gas reservoir at a depth of *3,300* feet in the Clinton sand in Ohio would be expected to have an initial pressure of about 1,300 pounds per square inch (psi), Since Brown shale formations produce gas at very low rates, it is difficult to determine an accurate initial reservoir pressure. However, shale wells that are shut in for long periods often exhibit pressures in the range of 0.125 times the depth, which is much less than would be expected in a normal oil or gas reservoir. The initial reservoir pressure is very important if the gas in the shale exists in a gaseous state, because the amount of gas in the reservoir measured at atmospheric conditions is proportional to the reservoir pressure. For example, all other things being equal, a reservoir with a pressure of 2,000 pounds per square inch absolute (psia) will contain twice as much gas in a given volume of reservoir rock when measured at atmospheric conditions as a similar reservoir at the same depth whose pressure is 1,000 psia.

Reservoir Evaluation Tools

Core Analysis

In drilling an oil or gas well with rotary tools (the drill bit rotates at the bottom of the hole as opposed to moving up and down as in cable-tool drilling), it is possible to use a special type of drill bit that works much like a doughnut cutter and permits the operator to cut plugs or cores from the formation and bring them to the surface as samples of the rock being drilled. This operation is referred to as "coring. " The samples so obtained can then be subjected to various types of analyses.

Geologists and engineers examine cores of Brown shale to detect fractures or joints, The visual appearance, odor, or taste of a core sample provides an indication of the presence of gas, oil, or water in the pores of the core.

After a quick gross examination, 6-inch long pieces of the core may be sealed in cans or other containers to maintain the fluid content insofar as possible. These samples are used to determine the porosity, permeability, and fluid saturation of the shale. It is important to note that the laboratory procedures used to analyze the Brown shale were designed for normal sandstone and limestone reservoirs which have much greater porosities and permeabilities.4

Basic to an understanding of the gas production potential of the Brown shale is the need for analytical techniques capable of accurately determining critical reservoir characteristics from core samples. If it is not possible to determine accurately from the core samples (1) the physical nature of the pore structure that constitutes the reservoir (subsurface gas container); (2) the percentage of the total bulk volume of the reservoir that is made up of pore space; (3) the ability of fluids to flow through these pores; and (4) the percent of pores occupied by gas, liquid hydrocarbons, solid hydrocarbons, and water, then there is much smaller chance of determining these same parameters from less direct methods such as electrical logs. A log is a record of some physical property (e.g., electrical resistivity or radioactivity) of the rocks penetrated in a well,

The "conventional" type of core analysis involves cutting a 3/4-inch-diameter, 1 -inch-long plug from the core, whereas the "whole core" type of analysis uses the entire sample which is 3-1 /2 to 4 inches in diameter and 6 inches long. "Whole-core" analysis is generally thought to be more applicable than the "conventional" type.

Permeability, Porosity, and Saturation

The permeability, porosity, and saturation of the Brown shale are vastly different from the same parameters of most gas-producing reservoirs. A general comparison of these characteristics is given in table 3. The Hugoton-Anadarko, San Juan, and Permian Basins represent some of the better known gas-producing areas. They tend to contain reservoirs that are on the "tight" (low permeability) side, as compared with offshore production, where the reservoirs may have a permeability of 1,000 mD and a porosity of 35 percent. Nevertheless, the typical sandstone reservoir has permeabilities and porosities that are much greater than those of

Brown shales. This is a strong indication that methods different from those used in conventional gas-producing reservoirs must be used to obtain commercial rates of production from the Brown shale. Development and evaluation of such methods can only come from basic research and field testing.

The characteristics of Brown shale listed in table 3 vary widely, even though the data presented are all from the same geographical region in southwestern West Virginia and eastern Kentucky. This variation is probably due principally to the heterogeneity of the shale itself.

it appears that whole-core analysis gives more meaningful information for the Brown shale because it includes the effects of joints and fractures. Conventional-core analysis, run on a small plug, will be affected by a fracture if one exists in such a sample, but the plug may not contain one even though fractures appear to be present every few inches in the Brown shale. Fractures caused by drilling and coring operations may produce spurious data from both coring analyses.

Table 3 does not indicate the very high permeabilities of some of the samples. The whole-core analysis of the Lincoln County well represents 19 samples distributed through 1,300 feet of shale. Three of these samples had permeabilities of 906 mD, 502 mD, and 93 mD, whereas the other 16 samples ranged from .0002 mD to .023 mD. Similarly, the whole-core analysis of the Perry County well represented 12 samples covering 64 feet, with two permeabilities of 9 mD and 23 mD and the others between 0.1 mD and 0.9 mD.

The Lincoln County, W.Va., whole-core analysis shown in table 3 is markedly different from the other Brown shale analyses. This is probably due to the manner in which the analysis was made. The cores from the Jackson and Perry County wells were analyzed using horizontal flow, while the analysis of the Lincoln County well was based on vertical flow. Since vertical flow is likely to encounter impermeable barriers of paper-thin laminae that would not affect horizontal flow, much lower permeabilities would be calculated. The lack of vertical communication would also result in reduced measured porosities. This Lincoln County core analysis also indicated a water saturation of 0.0 percent,[5,6] whereas the other shale analyses showed substantial water content, The Lincoln County analysis was based on centrifuge measurements, The centrifugal force created apparently did not exceed the capillary or other forces holding the water in the very small pores; hence, it appeared that the water saturation of the shale was 0,0 percent. These examples clearly emphasize the need for research in the area of core analysis of the Brown shale.

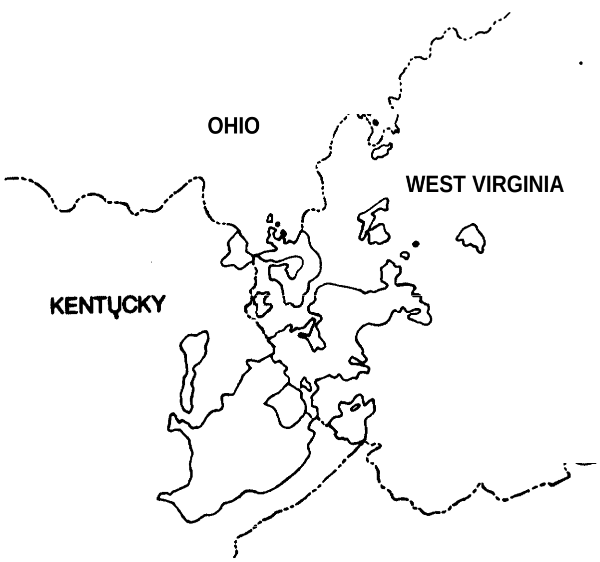
The Brown shale is characterized by a porosity of about 3 percent. However, a 3-percent porosity estimate may be too low. The operator who drilled the Lincoln County well canned whole-core samples throughout the entire 1,300 feet. All of these samples liberated sufficient natural gas to cause the pressure in the can to increase considerably, Although it took about 3 weeks for most of the cans to reach a static gas pressure, some of the cans containing the tighter sections of the shale were still increasing in pressure after a 2-month period,[7] The gas liberated in the cans had a volume greater than could be accounted for by the measured porosity and the assumed initial reservoir pressure. In other words, the gas-occupied porosity may be greater than the 3 percent currently indicated by the core analysis.

Because it takes as much as 2 months for the gas to escape or flow from a core sample 3.5 or 4 inches in diameter and 6 inches long, it may be that the amount of gas in the Brown shale can be most accurately determined by measuring the gas that escapes from core samples. In a normal oil and gas formation this would be impossible because most of the gas would escape from the core during normal canning or handling operations. However, in dealing with a material with such a low permeability as the Brown shale, it is obvious that very little gas is lost during the period of time necessary to remove the core from the bottom of the hole and place it in a container. The amount of gas lost from the cores during the canning operation would apparently be limited to the gas in the permeable fractures and would be negligible compared with the gas in the matrix of the Brown shale. Use of this method of determining the gas in the shale might eliminate the necessity of measuring the porosity, saturations, and reservoir pressure. A technique similar to this is used by the U.S. Bureau of Mines to determine the amount of natural gas in coal.[8]

Core Data Distribution

The gas-producing potential of the Brown shale cannot be realistically evaluated until its physical and chemical characteristics throughout the area have been determined. Even though there are about 10,000 wells currently producing gas from the Brown shale, coring to date has been limited almost entirely to the better-producing areas shown in figure 7. The data of table 3 relate only to wells in the producing area of Kentucky and West Virginia. Recent research has involved the coring of 12 experimental wells, but only 4 of these are very far outside currently producing areas.

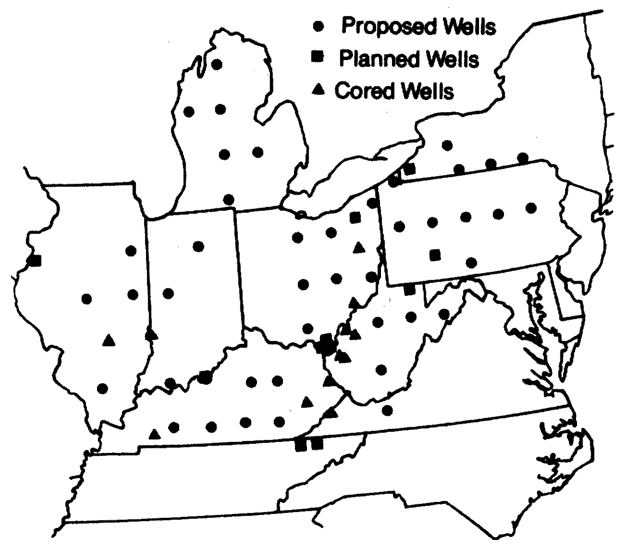
Figure 7. Major Devonian Shale Gas Production Areas



Source Energy Research and Development Admmistration.

An expanded shale inventory by the Energy Research and Development Administration (ERDA) will provide core samples from wells distributed across a wide expanse in the Appalachian Basin and areas to the west and northwest (figure 8). Such data are needed to evaluate the extent of the natural gas resource in the Devonian shales.

Figure 8. Location of Core Wells in a Proposed Inventory of Brown Shales by ERDA



Source Energy Research and Development Administration

Flow Tests

The actual significance of core analysis data and visual observation of core quality can only be obtained through flow tests of the wells, which determine how fast the gas can move through the shale. Due to the extremely low permeability of the shale, it may take several years to detect drainage of the potential drainage area of a well. To reduce the time required to determine flow rates in Brown shale, a special type of test is required. The so-called "isochronal" flow test involves determining flow rates under conditions where the entire drainage area of a well has not yet been affected and extrapolating the resulting data in order to estimate what the well behavior will be after the well has affected the entire drainage area.

Pressure buildup and drawdown tests are conducted to determine the significance or accuracy of the core-analysis or log-measured permeability, thickness, and saturation data.[9,10] A pressure drawdown analysis is a mathematical analysis of the pressure that results in the well due to continued production at a constant rate, whereas a pressure buildup analysis is a mathematical analysis of the increase in well pressure that results when the well is shut-in after being produced at a constant rate. The increase in wellhead pressure is determined at regular intervals for a specific number of days, weeks, or months.

Determining the initial pressure in the Brown shale is difficult and time consuming because of its low permeability. Reservoir pressures are normally determined by temporarily shutting in a well and then measuring the pressure in the well bore at the depth being investigated. Using this procedure after shutting in a well in the Brown shale will provide an accurate measure of the reservoir pressure only after weeks or months because of the time required for equilibrium pressure to be reached between the well bore and the adjoining shale pore space. " Much of the variation in formation pressure gradients (i.e., pressure per foot of depth) that has been observed and recorded might be caused by measurements taken before reservoir well bore pressures are equalized.lz1314

Logging

The term "logging" is applied to a variety of measurements made in a well by lowering a measuring device on an electric cable and recording variations of the particular physical property being measured. The plot of the data versus depth is known as a log. After permeabilities, porosities, and gas saturations have been determined from core analysis, logging techniques are used to measure various physical properties of the subsurface formations in place. Interpretation of well logs permits the determination of porosities, saturations, and permeabilities of the formation.

A wide variety of physical properties are traditionally measured in oil and gas wells in this manner. Some of these[15] are electrical resistivity, difference in electrical potential between mud in the well and the fluid in the rock (self-potential log), natural radioactivity (gamma-ray log), induced radioactivity (neutron log), speed of sound in the formation (sonic log), formation density, hole size (caliper log), temperature, sound intensity (sibilation log[16]), earth gravity,[17] and formation dip.

Most of these logs may be made either in empty holes or holes containing drilling fluid or water. Only a few types of logging can be done after casing has been set and cemented in the hole,

Whether or not water-based liquids damage the Brown shale by reducing its permeability is currently a subject of controversy.[18,19] This potential water damage is not only a problem in logging but also causes difficulty in drilling the well and in stimulating production by fracturing. Various combinations of logs must be run to obtain the porosity, water saturation, oil saturation, gas saturation, and organic content of formations. It may be possible to obtain logs in an empty hole, but it appears to be somewhat easier and simpler to use a series of wet-hole logs to determine these parameters,[20]

The sibilation, temperature, and Seisviewer logging techniques have special applications in the Brown shale.[21] The sibilation log is a high sensitivity, high frequency noise detector that can be used to determine where gas is entering the bore hole. The temperature log measures changes in temperature to detect where gas is entering the well bore. Both of these logging techniques are useful to determine which part of the well in a massive shale section should be treated. The Seisviewer log produces an acoustic picture of the bore hole. Such pictures often detect formation fractures and this is of course useful in the completion of the well.

Stimulation Techniques

Knowing that there is a great amount of gas in the Brown shale, where it is geographically, and which vertical portion of the formation is capable of producing it, is of no commercial use unless some method can be devised which will permit production of the gas at an acceptable rate. In other words, it makes little difference how much gas is in the shale unless some method can be developed to permit its production at an economic rate.

Evaluation of any drilling, stimulation, or production method is very difficult, because no two wells are the same. This problem is magnified considerably in dealing with the Brown shale, since its characteristics vary so widely from well to well even in the same area. Various techniques have been used to stimulate or increase the flow of gas from the shale. Early gas wells were stimulated by explosions ("shooting").[22] More recently, hydraulic fracturing has become a useful technique. There is no clear-cut experimental evidence concerning the relative merits of shooting and fracturing, although hydraulic fracturing generally produces slightly higher flow rates. Some companies reportedly continue to shoot their Brown shale wells while others claim fracturing gives superior results.[23] Other techniques are now being tested. Descriptions of several stimulation methods follow.

Explosive Stimulation

Explosions tend to develop fractures and shatter a formation, due to the rapidity with which the force is applied. Explosive stimulation does not affect a formation to as great a depth as does hydraulic fracturing.

Conventional Shooting. -Prior to about 1965, stimulation of oil and gas production from Brown shale was mostly limited to "shooting."[24] This entails setting and cementing casing in a drilled hole with its bottom above the prospective producing formation, then detonating explosives in the open (uncased) hole opposite the prospective producing formation. The explosion cracks and/or shatters the formation, thereby increasing the size of the well bore and the permeability of the formation around the enlarged well bore due to the cracks therein, Improving the permeability of even a few feet of the formation around the well bore normally greatly improves the capacity of that well to produce.[25] Explosive stimulation is the method that has been used in the completion of most existing Brown shale wells.[26]

An explosion in the well tends to fill the uncased well bore with shattered rock, The general consensus seems to be that rubble in the well reduces the productivity of the well.[27] Therefore, most operators attempt to remove the loose material from the well before trying to produce gas from it.

Most prospective Brown shale wells produce little or no gas before treatment. Consequently, a typical percentage increase in production cannot be predicted from stimulation efforts. Some wells have a dramatic increase in gas production after shooting, whereas others are not benefited.

Explosive Fracturing.—This technique combines some of the features of hydraulic fracturing and shooting.[28] The well is first fractured hydraulically and into those fractures explosives are injected and detonated. The explosion creates additional small fractures away from the large hydraulically induced fracture and may also shatter some of the material near the hydraulic fracture. It is theorized that the shattered material will hold open the fractures and make a system with a much higher productivity than a simple-hydraulic fracture would create. The outward explosive force of the artificial hydraulic fracture also tends to open up natural fractures that were encountered by the artificial hydraulic fracture. There has been very little experience with this technique in Devonian shales and it is therefore necessary to classify it as experimental. One of three tests involving ERDA and the Petroleum Technology Corporation has been performed.

Dynafrac.-Dynafrac is an experimental process in which several radiating fractures from the well bore are created and extended by using a slow-burning solid propellant above a column of fluid.[29] Mechanically, the shooting takes place as follows: 1) a small diameter solid propellant is centralized in the hole opposite the producing formation; 2) this solid propellant is covered with a liquid that extends upwards into the casing; 3) a slow-burning solid propellant is placed in a trapped airspace above the fluid level in the casing; 4) both the small-diameter charge and slow-burning solid propellant are fired at the same time; 5) the small-diameter charge communicates its force quickly to the surrounding formation and causes several radiating fractures to form; 6) the slow-burning solid propellant develops pressure more slowly and applies this pressure to the fluid beneath it; and 7) the fluid is forced out through the fracture formed by the explosion of the small diameter charge and the fractures are extended out into the formation.

The result of the Dynafrac treatment is several radiating fractures through the formation with a minimum of rubble in the well bore. Developing several radiating fractures from the well bore will give a better opportunity to encounter additional vertical fracture systems in the Devonian shale.

Nuclear Explosives.—The use of nuclear explosives in the Brown shale is a possible stimulation technique. However, the minimal success achieved in stimulating gas production in formations in the West is not encouraging.[30] The lack of successful nuclear shots and the sociopolitical difficulties of conducting nuclear explosions largely negate the possibility of using this technique to stimulate Devonian reservoirs.

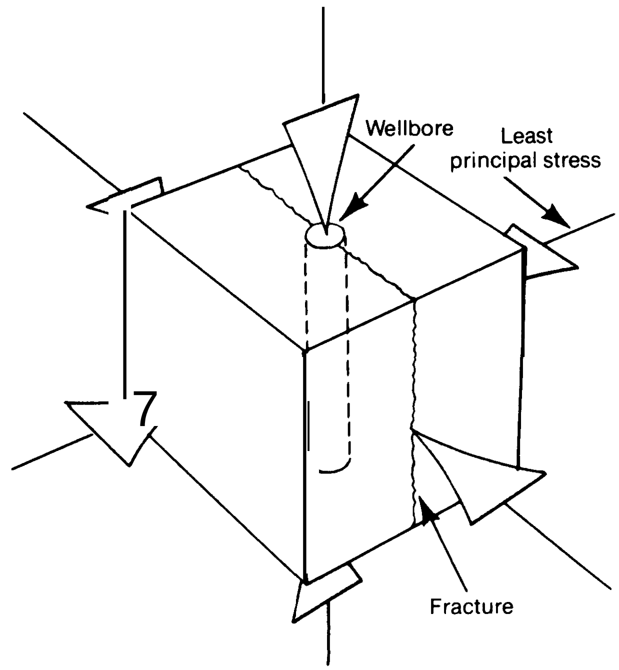
Hydraulic Fracturing

Hydraulic fracturing ("hydrofracturing") became available in the Appalachian Basin in the late 1950's. This technique involves injecting fluid into the formation at a rate and pressure sufficient to shatter and fracture the formation. The plane of the resulting fractures is generally vertical, except at very shallow depths (figure 9).[31] This fracture greatly increases the capacity of a well to produce.[32]

Hydraulic fracturing of a formation can often be made more effective by using a fluid that has a high viscosity. In order to keep a fracture open sand normally is added to fracture fluids, as it can prop open the fracture and give it high permeability. Because the Brown shale has extremely small-sized pores, it has been assumed that any contact of the formation by liquids, particularly water, would result in a great reduction in the permeability of the formation to gas. It is theorized that the liquid would be held by capillary attraction in the extremely small pores and the threshold pressure of this adsorbed liquid would be so high that much of the liquid would block the gas from flowing into the well bore. Also, water-based fluids might swell the clay particles in the shale and thus further reduce the permeability.[33]

Consequently, until recent years Devonian shale wells were not hydraulically fractured but stimulated entirely by shooting. Recently, however, some hydraulically fractured wells have performed better than adjacent wells shot with explosives. 34

Figure 9. Diagram Showing Relationship of Maximum Principal Stress and Least Principal Stress to the Plane of an Induced Hydraulic Fracture



Source Overbey, 1976, Energy Research and Development Administration Pub MERC/SP-76/2, Fig 3

One of the disadvantages of fracturing a gas well with a liquid is the length of time required for the fracture liquid to flow back into the well bore. In low-capacity gas wells, fracture fluids may interfere with the gas production for long periods of time.

Normal Hydraulic Fracturing.—Normal hydraulic fractures are defined and differentiated from massive hydraulic fractures by the amount of fluid in the treatment. Any fracture requiring less than 100,000 gallons is defined as a normal fracture. On the other hand, the use of foam or gas as described later in this section is differentiated from a normal fracture treatment by reason of the unusual fluids being used for fracturing.

Most fracture treatments of the Brown shale are now made using water-based fluids with chemicals added to minimize the effect of water on the clays or minimize reductions in permeability.

It is very difficult to quantify the effect of fracturing on gas production, because most Brown shale wells produce little or no gas before treatment, Generally, increased gas production results from fracturing Brown shale.

Massive Hydraulic Fracturing [35,36, 37, 38]—A massive hydraulic fracture is defined as one in which more than 100,000 gallons of fluid are used in the fracture treatment. Some massive hydraulic fractures have used over 1 million gallons of fluid.

Questions continue to exist concerning the lateral extent of fractures resulting from massive hydraulic treatment.[39] In many cases, subsequent flow tests have not corroborated the formation of a large fracture. Conflicting opinions exist concerning the advisability of massive fracturing. A major difficulty has been the tendency of the fracture to leave the target area of a formation and migrate into portions of a formation that do not contain oil or gas.[40] Fluids moving into nonproductive parts of the shale sequence will not increase gas production. This problem may be minimal in Brown shale, since shale fractures more readily than most formations above and below it.

Another difficulty with massive hydraulic fractures is the long cleanup time required. As much as 6 months may be required to get all of the mobile fracture fluid out of a well.[41, 42] An additional problem is that more than an acre of surface space is needed to accommodate the equipment required for a massive treatment. In hilly Appalachia, flat sites of more than an acre are not easily found or constructed, particularly if the well is located on a steep mountain side or in a narrow gorge,

In spite of all the problems inherent in massive hydraulic fracturing, this stimulation technique may still have potential in the Brown shale.[43]

fracturing With Foam [44, 45, 46].—There is considerable question about the extent of the damage done to Devonian shale formations when liquids, especially water, come in contact with the shale.[47, 48] Mixing of appropriate chemicals with the treating water minimizes the damage to the shale.[49] Foam, a mixture of nitrogen, water, and a foaming agent, tends to minimize the leak-off of the fracture fluids into associated permeability zones.[50]

A properly compounded foam can shorten the time needed to recover fracture fluid after a treatmerit.[51] When injected, the foam is compressed; after fracturing, it expands towards the lower pressure at the well bore and helps expel the fracture fluid from the rock into the well. A time- and/or temperature-effective emulsion breaker can be added to the foam so that by the time the well is ready to produce, the foam has broken into a mixture of gas and liquid, which facilitates cleaning the well bore.[52]

Fracturing Withl Gas[53].-Using a liquefied gas as a fracturing agent overcomes cleanup difficulties and potential damage to the formation by liquids; no water is used and the liquefied gas vaporizes as the pressure in the well bore is dropped, However, this technique is quite expensive.

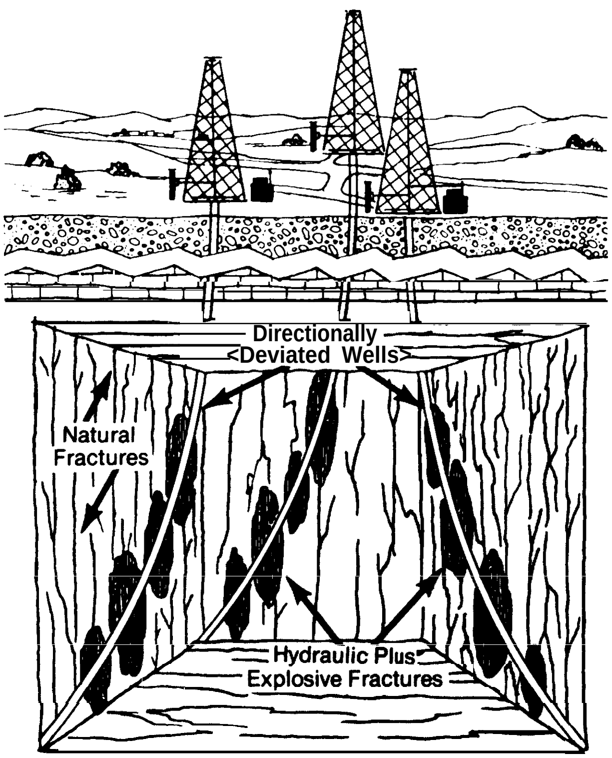
Dendritic Fracturing [54], —Instead of obtaining one long fracture, the Dendritic fracture method attempts to form a fracture that branches in many directions.[55] After one small fracture has been created, the well system is placed on production for a very short time to reverse the stress in the formation. Additional small fractures along the main fracture are thought to form due to this reversal of stress. When a new fracture force is applied, one or more small fractures branching from the large fracture are extended. This procedure of fracture-relaxation is continued to develop a Dendritic-shaped fracture.

Assertions that such a Dendritic fracture can actually be formed by this technique still require confirmation. [56] If the technique does cause fractures to develop in a variety of directions and thus intercept a large number of the natural parallel fractures in the Brown shale, the technique might have potential for increasing gas production from them.

Directional Drilling [57, 58].—Directional drilling is another production stimulation technique that may have potential in the Brown shale. Because most natural fractures in the Brown shale appear to be parallel vertical fractures,[59] it is theorized that a well drilled diagonally across this vertical system of fractures would encounter more of the fractures and thus result in substantially greater production. Very little directional drilling has been done in the potential producing area of the Brown shale.[60]

Considerable difficulty was encountered in an experiment with directional wells in the Brown shale.[61] Although the mechanics of the drilling operation were successful (figure 1 O), gas production did not meet expectations and therefore only one of three planned wells was drilled.

Figure 10. Deviated Wells and Earth Fracture Systems Process



Source Energy Research and Development Administration

Other Stimulation Methods

Many, other techniques have been proposed for recovering gas from the Brown shale, although most of these are techniques that have been used to recover oil rather than gas.

Microbial.—It has been proposed that bacteria could be introduced into oil reservoirs to form gases and/or change the interracial tension and viscosities to make the trapped oil more mobile. Microbial techniques do not appear to have great potential for gas recovery where the gas mobility is limited by the tight matrix of the Brown shale. Although there are bacteria able to withstand temperatures and pressures found at a depth of 3,000 to 4,000 feet, none are known that will both successfully generate useful modifying products in sufficient amounts and also tolerate the chemical and thermal environments at those depths. The job of inoculating a large area of very low-permeability shale would be very difficult, if not impossible, unless a microbial hydrofracture technique could be perfected. Further, any strain of bacteria developed would need to be carefully screened for potential environmental impacts. Even should the conceptual process be feasible, it is unlikely that the necessary strains could be developed, field tested, and put into commercial operation within time to influence shale gas recovery by the year 2000.

Thermal.—A variety of thermal methods have been successfully used to increase recovery of oil from various formations. The value of these methods for reducing the viscosity of gas would appear to be minimal, although laboratory results indicate that gas is released from Brown shale faster when the shale is heated. This appears to be due to the expansion of gas in the shale and the resulting increase in pressure which forces the gas from the shale at a higher rate. It seems possible that such an effect might be useful in the Devonian shale reservoir. Burning of gas in the Devonian shale (or applying heat by other means) could increase gas pressures locally and cause the gas to move more rapidly toward the well. The cost of supplying oxygen to the formation to maintain a fire, and the poor heat conductivity of shales in general, make it unlikely that thermal processes would be economical.

Mining. -Brown shale outcrops cover an extremely wide area in the Appalachian Basin (figure 3). It is technologically possible to mine the Brown shale, then recover the gas from the shale by means of various thermal-chemical methods. Such methods might also recover any liquid hydrocarbons contained in the Brown shale. Because of the low volume of gas in the Brown shale, costs of mining and retorting probably would be great. Likewise, environmental problems associated with processing the shale and disposing of the spent shale could be obstacles to any large-scale mining venture. It appears that most proposed approaches to recovering gas from strip mined Brown shale will not result in net energy gains. Producing shale gas by subjecting mined shale to various thermal-chemical processes will probably result in costs of $5.00 to $6.00 per Mcf, comparable to, or higher than the cost of producing high Btu gas from coal.

Potential of Alternative Stimulation Methods

None of the thermal, microbial, or thermal-chemical methods proposed for recovering gas from the Brown shale appear to have a high potential for recovering a significant amount of gas within the next 20 years. It has been shown that thermal, microbial, and thermal-chemical techniques are capable of recovering gas from the Brown shale under very limited and controlled conditions, but the physical and economic feasibility of commercial operation has not been demonstrated to date.

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[42]E.J. Ranostaj, "Massive Hydraulic Fracturing the Eastern Devonian Shales," ERDA Contract No. E (46-1)-8014, 1976.

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[48]E.J. Ranostaj, "Massive Hydraulic Fracturing the Eastern Devonian Shales," ERDA Contract No. E (46-1)-8014, 1976.

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[50]Final Report—Well #7239, Perry County, Ky., ERDA-MERC, July 1975.

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[54]Hydraulic Fracturing Process Using Reverse Flow, U.S. Patent No. 3,933,205, Jan. 20, 1976.

[55]Ibid.

[56]Ibid.

[57]W.K. Overbey and W.M. Ryan, "Drilling a Directionally Deviated Well to Simulate Gas Production from a Marginal Reservoir in Southern West Virgin ia,' ERDA-MERC/TPR-76/3, 1976.

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[60]W. K. Overbey and W.M. Ryan, "Drilling a Directionally Deviated Well to Simulate Gas Production from a Marginal Reservoir in Southern West Virgin i a," ERDA-MERC/TPR-76/3, 1976.

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VI. Economics of Brown Shale Gas Production

VI. Economics of Brown Shale Gas Production

There are three principal areas of uncertainty in evaluating the commercial potential of natural gas production from the Devonian shales. These basic uncertainties are:

- economic
- technological, and
- geologic.

The economic uncertainties involve primarily expected well head prices and the tax treatment of income from natural gas production, but economic uncertainty also intersects technological uncertainty. The areas of intersection involve possible progress in drilling technology and the effects of stimulation techniques on production. The principal geologic uncertainty involves the Brown shale resource base, i.e., how much of the Brown shale is a high-quality, gas-productive resource, how much is medium quality, and how much is low quality? As natural gas prices increase to reflect the value of this resource more closely, it is reasonable to expect that relatively large amounts of shale gas might become economically attractive. What is not now adequately known, and can only be determined from actual drilling and production experience over a wide geographic area, is the quantity of high-, medium-, and low-quality areas of Brown shale. [1]

The approach used here is to deal with economic uncertainty by considering a range of wellhead prices and tax treatments. These ranges of price and tax cases are used to evaluate the after-tax net-present values (ATNPV—Current worth of a flow of income after taxes); of gas wells drilled into the Brown shale in three geographic localities in the Appalachian Basin. The drilling costs, dry-hole experience, and production profile information used in the ATNPV calculations are the actual data for each of the three localities,[2] and each locality is evaluated separately.[3] The three were chosen as examples of high-, medium-, and lower-quality resources for which adequate data were available on a consistent basis to support ATNPV calculations under alternative assumptions concerning the price and tax determinants of economic incentives. It must be realized that these three localities are situated in a small area of the Appalachian Basin which is known to be gas productive. Therefore, the terms high-quality, medium-quality, and low-quality resource are relative to each other only, and production data from these three localities cannot be extrapolated directly to the entire 163,000-square-mile extent of the Appalachian Basin.

Production data from 490 shale wells in the gas-productive area of the Appalachian Basin were used to estimate the potential production from other areas of the Appalachian Basin where shale gas production might be economically feasible. This part of the analysis is the point of most crucial interest and the weakest link in the overall analysis, Until substantially more drilling has been done over a wide area, the amount of the Brown shale resource with economic potential will not be known with any more confidence than the judgmentally plausible estimates used in

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[1] See the section titled *Extent of the Economically Producible Area* for rationale used to estimate the quantity of commercially productive Brown shale in the Appalachian Basin,

[2] The after tax net-present value (ATNPV) calculations were made with the aid of a computerized routine developed by Drs. Robert Kalter and Wallace Tyner. This ATNPV calculation routine is described in Wallace E, Tyner and Robert J. Kalter, "A Simulation Model for Resource Policy Evaluation, " Cornell Agricultural Economics Staff Paper No. 76-35, November 1976.

[3] These individual localities are not homogeneous in terms of either the quality of the resource base or the stimulation technique used. As a result, seven types of Brown shale gas production in the Appalachian Basin are actually evaluated on an ATNPV basis.

this analysis. q The assumptions used here are explicit, and are subject to sensitivity variation and revision as more actual drilling results become available.

The general result of the analysis is relatively optimistic:

- if 10 percent of the total Appalachian Basin shale is as attractive as the higher quality resources examined here;[5]
- if there" is no improvement in drilling technology or stimulation techniques; and
- if current tax treatment of income from natural gas production continues; then,
- at wellhead prices for natural gas in the $2.00 to $3.00 per Mcf range, it is not unreasonable to conclude that the Brown shale of the Appalachian Basin may have a production potential in the neighborhood of 1 trillion cubic feet (Tcf) per year for a considerable future period.

Such a level of production would require a substantial effort (69,000 wells), but the additional supply is not inconsequential in the context of the current and prospective U.S. natural gas situation. One trillion cubic feet (Tcf) per year of Brown shale gas would be equivalent to about 5 percent of current U.S. production.

Price, Tax, and Other Economic Assumptions

In recent years, wellhead gas prices have increased substantially and the tax treatment of income from gas production has become less generous. In this analysis, four alternative prices for prospective Brown shale gas and four tax cases are considered, The basic price and tax assumptions are firmly rooted in the current facts of interstate and intrastate gas markets and internal Revenue Service (IRS) treatment of income from gas production. The additional price alternatives and tax cases are designed to cover a broader range of possibilities for enhanced economic incentives and to test the sensitivity of the ATNPV of shale gas potential to such possibilities.

Price Assumptions

The four alternative assumed prices are:

- $1.42 per Mcf,
- $2.00 per Mcf,
- $2.50 per Mcf, and
- $3.00 per Mcf.

The current Federal Power Commission (FPC) wellhead ceiling price for sales of natural gas in interstate commerce is $1.42 per Mcf.[6] This price is subject to a 1 -cent escalation every 3 months. It also contains a provision for an upward proportional adjustment if the gas sold contains more than 1,000 Btu's per cubic foot.[7] Much of the gas from the Devonian shale of the Appalachian Plateaus has a substantially greater Btu content than the FPC standard upon which the $1.42 per Mcf new-gas ceiling rate is based—it is not uncommon for gas from Brown shale to have a Btu content as high as 1,350 Btu's per cubic foot. In addition, although a considerable part of the area of Brown shale potential, particularly in West Virginia, is served by interstate pipelines subject to FPC ceiling price regulation, much

[4] There are approximately 10,000 wells producing gas from the Brown shale. But data for many of these wells are not readily available, a large fraction of the wells are in a relatively small area, and for many wells production from the Brown shale is commingled with production from other zones. It is possible that careful screening and analysis of these data would significantly improve our current knowledge of the Brown shale resource, but such an effort was beyond the scope of this assessment.

[5] The rationale for considering 10 percent of the Appalachian Basin as higher-quality resources is presented in the section of this report titled, *Extent of the Economically Producible Area.*

[6] Federal power Commission, opinion No.770-A, p. 181.

[7] Ibid, pp. 186-187.

prospective shale gas may be sold in intrastate commerce. prices in intrastate markets are typically higher than those in interstate markets.[8] For these two reasons—Btu adjustment and intrastate market sales—the current $1.42 Mcf ceiling price may be considered a lower-limit base case on wellhead prices, which will be a determinant of the economic feasibility of Brown shale production.[9] In addition, there are the prospects of higher FPC ceilings for new gas or of congressional deregulation of new gas sales. Both of these later possibilities support treatment of $1.42 per Mcf as a lower limit base case.

The weighted average price per Mcf for national natural gas sales in intrastate commerce for new contracts signed in the second quarter of 1976 was $1.60 per Mcf. Many contracts were in the neighborhood of $2.25 per Mcf. Prices in this range can be considered the leading edge of the intrastate gas market. Intrastate sales of gas from Brown shale in Ohio and Kentucky have brought prices of over $2.00 per Mcf, The recent trends of both interstate and intrastate wellhead prices have been upward. Current shortages suggest these trends will continue. Leasing, drilling, and well-completion decisions on the basis of price expectations of $2.00 per Mcf or more for Brown shale gas in various areas are therefore not an unreasonable assumption. The second alternative price is $2,00 per Mcf.

The third and fourth alternative prices are $2.50 and $3.00 per Mcf. The prices of alternative fuels such as fuel oil, propane, synthetic natural gas (SNG), or liquefied natural gas (LNG) are either at or substantially above these values on a Btu basis. Use of prices in this range is therefore appropriate in the ATNPV calculations in order to test the potential sensitivity of natural gas production from the Brown shale to substantially enhanced economic incentives. It must be emphasized, however, that these values are not price projections or forecasts. For the purposes of the calculations reported herein, they are merely elements of the sensitivity analysis.

All prices are specified in constant 1976 dollars. In each of the ATNPV calculations reported below, if a price of $1.42 per Mcf (or $2.00, $2.50, or $3.00) is specified that price is assumed to hold in constant 1976 dollars for the life of production. Drilling, well-completion, and operating costs are also specified in constant 1976 dollars. These cost components are discussed in more detail in the section on cost and technological considerations.

Tax Assumptions

Four cases for the tax treatment of income from gas production are considered in the ATNPV calculations reported below. These are:

- zero percentage depletion allowance and no investment tax credit;
- 22-percent depletion allowance and no investment tax credit;
- zero percentage depletion allowance and a 10-percent investment tax credit; and,
- 22-percent depletion allowance and a 10-percent investment tax credit.

The assumption of zero percentage depletion allowance and no investment tax credit is consistent with the current treatment of income from natural gas production for producers with average daily output in excess of 2,000 barrels of oil or 12 MMcf of natural gas. Relative to typical lease output for Devonian shale production, these are large amounts of natural gas. But most U.S. oil and natural gas output is produced by the very large number of operators (whether corporations, partnerships, or sole proprietorships, etc.) with production above these cutoff levels. If economic incentives are sufficient to make Brown shale prospects an attractive investment opportunity, and if the Brown shale resource is

[8] See Federal Power Commission form 45 data.

[9] Wellhead prices also reflect unit transportation costs to end-use markets. Unit transportation costs are a decreasing function of the volume of shipments. Shale gas output per producing area may sometimes be small enough that relatively high unit transportation costs have an adverse effect on the wellhead netback from end-use markets. For the purposes of the analysis here, we assume that the high-quality Btu characteristics of Brown shale, its proximity to major markets, the possibility of intrastate sales, the form of pipeline and distribution company regulation, and the cost of alternative supplies all operate to make the $1,42 per Mcf value a lower-limit base case.

extensive enough to allow significant volumes of production, then this tax treatment is relevant for many potential Brown shale operators. Together with the $1.42 per Mcf price assumption, this tax treatment defines the lower-limit base case considered here.

The 22-percent depletion allowance and zero investment tax credit is the tax treatment relevant to many, perhaps most, current Brown shale operators. The small-producer exemption phases down, on an allowable output basis over the period 1976-80, to 1,000 barrels of oil or 6 million cubic feet of gas per day. Beginning in 1981, the applicable percentage depletion allowance rate begins to decrease on a phased basis from 22 percent until it reaches 15 percent in 1983. However, a 22-percent depletion allowance rate for production not in excess of 1,000 barrels of oil per day or 6 million cubic feet of natural gas per day will be allowed for production which results from enhanced or tertiary recovery. Because of the following reasons:

- eligibility of small Brown shale operators for 22-percent depletion allowance until 1981,
- importance of the early years' receipts in the net present value calculations, and
- possible classification of Brown shale operations as tertiary or enhanced recovery production;

the second tax case is a relevant component of the sensitivity analysis for the economic feasibility of Brown shale gas supplies.[10]

The third tax case considered puts the tax treatment of income from gas production on more of an equal footing with the tax treatment of other nonextractive investment opportunities in the U.S. economy. In this third case, percentage depletion is set at zero and an investment tax credit of 10 percent is assumed.

The fourth tax case is a liberalized tax treatment of income from gas production. Percentage depletion is assumed at 22 percent and a 10-percent investment tax credit is allowed.

In all four tax cases considered, no change is assumed in the tax treatment for expensing of intangible drilling costs.

State income and severance taxes are assumed to be equivalent to an average State income tax of 12 percent. Actual income and severance tax rates in the Appalachian Basin States in which increased Brown shale production may become a factor are typically lower.[11] However, experience in Gulf Coast and Southwestern States, where severance taxes have been converted from a unit to an ad valorem basis, suggests that it is prudent to use conservative State tax rates for the sensitivity analysis reported below,

Other Economic Assumptions

The ATNPV calculations are also sensitive to a number of other factors. These include:

- the discount rate;
- the lag between initial investment costs and the commencement of sales;
- the time profile of production;
- the amount of recoverable reserves per unit of investment cost; and
- operating costs.

The discount rate used in the ATNPV calculations reported below is 10 percent in real terms after taxes. ("Real terms" means in constant dollars adjusted for inflation.) Many individual entrepreneurs and corporate decision makers now require rates-of-return for project evaluation which are substantially in excess of 10 percent, but these higher rates are expressed in current

[10] Consideration of this tax case is not an implicit recommendation for differential tax treatment by size or status of operator. Rather, it is simply a recognition of the current law and the fact that different categories of operators focus their activities in different areas and on different types of prospects.

[11] The highest marginal rate for corporate income tax is 5.8 percent in Kentucky, 8 percent in Ohio, and 6 percent in West Virginia. Ad valorem and severance taxes for these States are approximately 2,2 percent for Kentucky, 2.6 percent for Ohio, and 10 percent for West Virginia of typical gross revenues expected for a Brown shale well.

dollar terms and include an inflationary adjustment. In addition, there is often substantial process or outcome risk associated with the projects in question.[12] There is considerable evidence that the petroleum industry has been willing to commit substantial investment funds on an ongoing basis in situations in which the realized rate-of-return was in the neighborhood of 10 percent after taxes.[13] For this reason, and also because the lower-limit base case overstates the after tax costs of smaller operators, a 1 O-percent after-tax discount factor is used.

There is commonly a lag between the time when initial investment expenses are incurred and actual production commences. In many cases, for example offshore production, this lag may be measured in years. In proven onshore areas connecting a well to a pipeline network where no unusual drilling, well-completion, or production problems arise, the lag may be relatively short. There are instances in which the lag between the time when an Appalachian Basin well to the Brown shale is spudded in and the start of production has been as short as 1 week. The critical determinants of the lag between initial investment and the commencement of the revenues (if any) which justify the commitment of the funds are:

- the distance from an existing pipeline;
- the expected volume of production for the area;
- the ease or difficulty of acquiring pipeline right of way; and
- the costs per well of pipeline construction.

Existing Brown shale production has generally been developed in areas close to an existing pipeline network. Under these circumstances, lags between the initial investment costs and the realization of production revenues have been relatively short-on the order of a few weeks. On a prospective basis, the average lag may be expected to increase. But if Brown shale development taps a significant resource base, the pipeline network will follow it and the lag can be expected to close. In the ATNPV calculations reported below, the average lag assumed between the initial investment expenditure and the realization of production revenues is 1 year. This is considerably greater than current experience, but is not inconsistent with a prudent approach to possible future lags.

One of the most critical factors concerning Brown shale gas is the time profile of production. A typical shale reservoir is relatively small and has a very stretched-out production profile. Flow rates are currently being accelerated by artificial stimulation through hydrofracturing or shooting the well bore with explosives. But even under the best circumstances, a relatively small fraction of total recoverable reserves is produced in the earlier years of the life of the reservoir. [n figure 11, the production profile of a typical offshore

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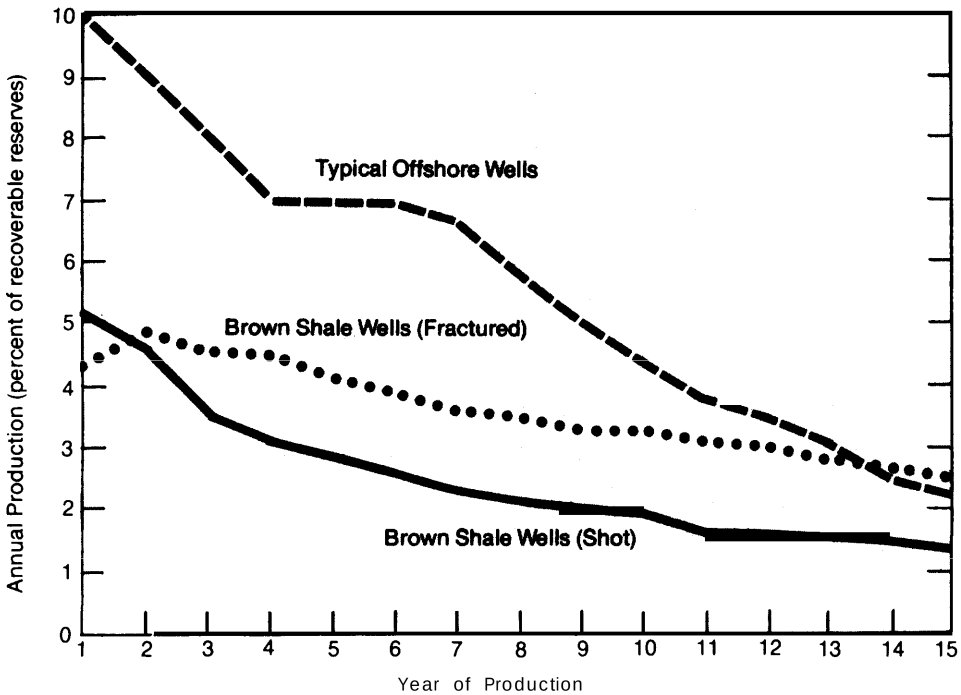
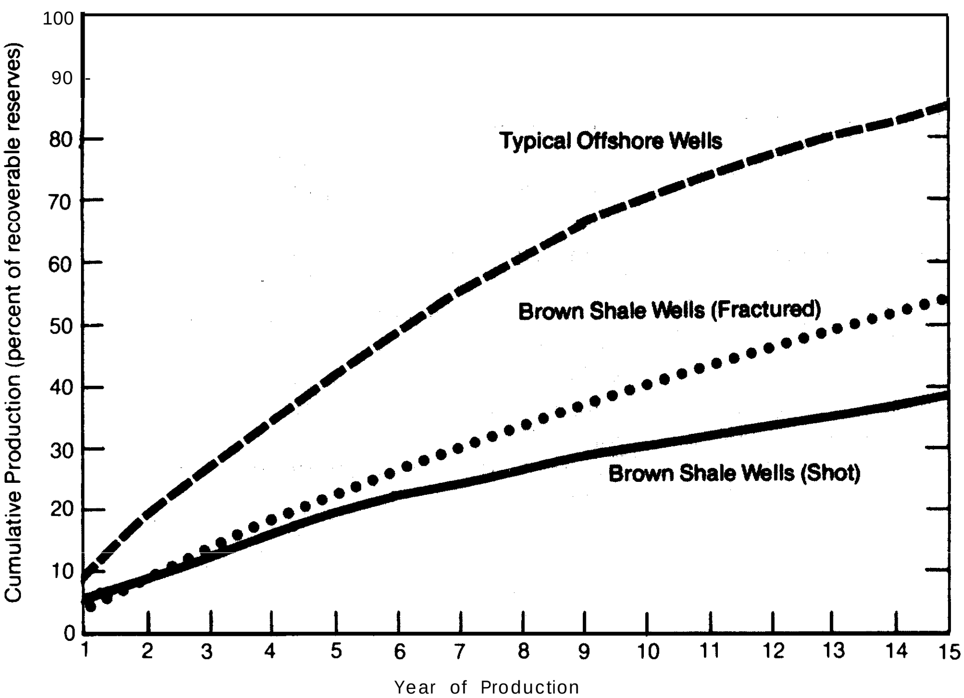
[12] See, for example, *Enhanced Oil Recovery,* the National Petroleum Council, Washington, D. C., pp. 19-62, 1976.

[13] There have been a number of studies of the rate of return to offshore activity. These studies indicate that in general, oil companies have earned rates of return in offshore activity which are consistent with effective competition. These studies include: T.D. Barrow, "Economics of Offshore Development, " *Exploration and Economics of the Petroleum Industry,* Bender, New York, N. Y., 1967; "Post Appraisal of Recent Sales, " op. cit., Vol. 7, pp. 69-89; Walter J. Mead, estimates contained in Nossaman, Waters, Scott, Kreuger, and Riordan, "Study of Outer Continental Shelf Lands of the United States, " Public Land Law Commission, U.S. Department of Commerce/National Bureau of Standards, pp. 521-527, revised 1969; "The Role of Petroleum and Natural Gas From the Outer Continental Shelf in the National Supply of Petroleum and Natural Gas, " U.S. Department of the Interior, Bureau of Land Management, Technical Bulletin No. 5, May, 1970; L.K. Weaver, H.F. Pierce, and C.J. Jirik, "Offshore Petroleum Studies: Composition of the Offshore U.S. Petroleum Industry and Estimated Costs of Producing Petroleum in the Gulf of Mexico, " U.S. Department of the Interior, Bureau of Mines, Information Circular 8557, Washington, D. C., 1972; "Rates of Return on the OCS," U.S. Department of the Interior, Office of the OCS Program Coordination, May 7, 1975; Jessee W. Markham, "The Competitive Effects of Joint Bidding by Oil Companies for Offshore Lease Sales, " op. cit.; and E.W. Erickson and R.M. Spann, "An Analysis of the Competitive Effects of Joint Ventures in the Bidding for Tracts in OCS Offshore Lease Sales, " in hearings before the Special Subcommittee on Integrated Oil Operations of the Senate Committee on Integrated Oil Operations of the Senate Committee on the Interior and Insular Affairs, *Market Performance and Competition in the petroleum Industry,* Washington, D.C., pp. 1691-1745, 1974. The best interpretation of these studies is that there is a substantial body of evidence which unanimously supports the conclusion that in oftshore activity 011 companies have not, in general, earned rates of return in excess of the competitive normal level,

Figure 11. Comparison of Gas Production from Brown Shale Wells and a Typical Offshore Gas Well





Source. OCS production rates developed by Exxon, USA for the Federal Power Commission's Natural Gas Survey. Rates for Brown shale production from over 200 wells in Kentucky and West Virginia (Columbia Gas Company, Ray Resources Corp, and Consolidated Gas Co).

natural gas well is compared with those of two typical Brown shale wells. In the first 15 years of production, only 38 to 54 percent of total recoverable shale gas reserves are produced, but about 85 percent of the reserves in the offshore reservoir are produced. Production which is weighted toward the later years in the production profile has a weaker positive effect upon the ATNPV of the prospect. This production profile, together with the relatively small volume of reserves per unit of investment cost, has been the principal reason that, until recently, Brown shale gas production has been economically submarginal.

Cost and Technological Characteristics of Brown Shale Production in Three Localities

Production data have been obtained from three gas-productive locations in the Appalachian Basin, These localities, in descending order of general investment attractiveness, are Cottageville, W.Va. (high quality); Clendenin, W.Va. (medium quality); and Perry County, Ky. (lower quality). The quality designations reflect geologic and economic characteristics of each region and are not intended to reflect any differences in the actual Btu content of the natural gas in the fields. The 15-year production profiles are given in table 4. In the high-quality area, production data were available only from shot wells. These figures are the averages of actual production data for 13 wells in this field for the 15-year period.

In the medium-quality shale, data were available for both shot and hydrofractured wells, but only for 5 years. The rest of the profiles were extrapolated using production decline curves for Brown shale wells developed for the region.[14]

[14] Bagnall and Ryan, "The Geology, Reserves and Production Characteristics of the Devonian Shale in Southwestern West Virginia," figure 11, *Devonian Shale-Production and Potential,* ERDA, 1976.

Table 4
Production Statistics of Natural Gas From Brown Shale in Three Localities

(Mcf Per Year)

Locales:	High Quality	Medium Quality		Lower Quality			
				Good		Bad	
Stimulation:	Shot	Frac *	Shot	Frac	Shot	Frac	Shot
Year							
1	36,318	17,989	17,858	21,250	18,750	11,400	6,800
2	29,490	20,227	16,053	20,850	15,880	10,900	5,000
3	23,883	17,978	12,342	20,600	13,600	9,200	5,600
4	20,071	18,570	11,001	17,700	11,480	9,600	5,100
5	17,439	17,000	10,000	18,350	1-1,170	8,300	5,400
6	15,980	16,000	9,000	17,290	11,080	7,500	5,300
7	14,879	15,000	8,200	17,000	10,000	6,900	5,000
8	13,464	14,500	7,500	16,300	9,300	6,300	4,950
9	12,772	13,800	7,000	15,600	8,700	5,800	4,900
10	12,498	13,500	6,500	15,000	8,200	5,050	4,800
11	11,661	12,700	6,100	14,500	7,800	4,750	4,700
12	11,304	12,200	5,800	13,800	7,500	4,500	4,600
13	11,131	11,700	5,500	13,300	7,200	4,250	4,550
14	10,842	11,300	5,200	12,800	7,000	4,050	4,450
15	9,766	10,800	5,000	12,300	6,800	3,850	4,400

Source: Production and cost data on Brown shale operations are averages from over 200 wells in Kentucky and West Virginia (Columbia Gas Co., Ray Resources Corp., and Consolidated Gas).

*Hydrofracturing is commonly referred to as "frac" which will be used as an abbreviation in tables in this report, Because of great, variability in the production from the wells in the lower-quality location, the wells were separated into two groups-good and bad-based solely on their production rates. Shot and hydrofractured wells fell into both groups. Fifty-nine percent of the wells in this locality fell into the good group, while the remaining *41* percent were in the bad group. One might be misled by looking only at the good groups in this locality for comparison with the high- and medium-quality locality, because one assumes a risk of having a bad well in this locality 41 percent of the time. So, while one can get a good well from the lower-quality locality, the investment potential on average is less attractive than in the other localities.

In judging the investment potential of the localities, there is concern regarding the costs associated with the production: the initial costs for drilling and stimulating the wells, the annual operating costs, and the indirect cost from the risk of drilling a "dry hole. " Table 5 shows the average of the direct initial costs for drilling and stimulating wells in the localities. The differences in drilling costs reflect differences in depth of the wells in the various portions of the Appalachian Basin and in the drilling costs per foot, which are a function of the geologic and topographic characteristics of the localities. Detailed cost figures are presented in tables 13 through 17 at the end of this chapter.

Table 5
Direct investment Costs for Producing Wells in Brown Shale

(Dollars in thousands, 1976 constant)

Locality	Stimulation Technique	Average Cost: Intan-gible	Average Cost: Tan-gible	Total
High Quality	Shot	$ 80.5	$23.9	$104.4
Medium Quality	Frac	121.7	38.7	160.4
	Shot	98.9	20.8	119.7
Lower Quality	Frac	115.9	40.0	155.9
	Shot	94.3	27.4	121.7

Drilling costs in the lower-quality locality were taken to be about $10 per foot, whereas they were about $9 per foot in the other localities. It is recognized that in some other areas these costs may be as low as $6.50 per foot, but these areas are readily accessible and have easily worked geologic formations. In light of the potential for technological advances in the drilling process, a low estimate is given in table 6, approximately reflecting a 10-percent reduction in actual drilling costs.[15] The effect of lower drilling costs or of cheaper stimulation techniques on the investment decision in the localities can be examined by comparing the reduction in average and low estimates with the ATNPV for the different scenarios as displayed in tables 8 through 11.

The effect of progress in drilling technology or of improvement in stimulation procedures, which reduces the initial investment cost per unit of reserves, will be to extend the economically feasible portion of the Devonian shale resource. A 10-percent decrease in real drilling costs, such as that assumed for purposes of example in table 6, would make some of the prospects in tables 8

[15] See, for example, Franklin M. Fisher, "Technological Change and the Drilling Cost-Depth Relationship, 1960 -66," in E.W. Erickson and L. Waverman, editors, *The Energy Question, Vol. 2, North* America, University of Toronto, 1974.

Table 6
Effect of Reduction in Initial Investment Cost

(Dollars in thousands, 1976 constant)

Locality	Stimulation Technique	Average Cost	Low Estimate	Change in ATNPV as a Result of Reduced Costs*
High Quality.	Shot	$104.4	$ 90.4	+$6.5
Medium Quality	Frac	158.4	137,4	+ 9,6
	Shot	119.7	102.6	+ 7.8
Lower Quality	Frac	155.9	144.3	+ 5.3
	Shot	120.5	110.8	+ 4.4

● The only change in tax effect considered is in the first-year writeoff of intangibles.

through 11, which have small negative ATNPV values, economically attractive.[16]

The average costs are separated into intangible and tangible items because of the impact of the different tax treatment as to expensing and capitalizing these costs. The intangible costs were set to include a management fee of about 15 percent and a contingency fee of 6 percent. While these figures may be high for some operators at some locations, they are typical of current charges and are representative of anticipated costs if an extensive effort to develop the Brown shale should occur.

The annual operating costs are set at $1,800 per well. While some operators may use a substantially cheaper well-tending service, this figure provides a cushion for expenses resulting from equipment repair.

An additional cost to be considered is that associated with the risk of a "dry hole. " This risk is difficult to assess because of the difficulty in determining which wells are in fact "dry holes." Of course, the clearest case is the hole which produces no natural gas at all. The problem arises when there is some gas but the flow is not sufficient to make the well profitable based on its own operations. The decision to continue the final casing of the well would be based on the additional cost of finishing the well rather than the amount already invested. However, it is complicated not only by the uncertainty of the price to be received for the gas but also by its usefulness to the investors as a tax shelter for other income. In addition, under syndication, not only do marginal tax rates vary among investors and operators, but which costs are sunk and which are incremental may be different to investors and operators. Hence, wells which would be economically unattractive on a total basis may be brought into production for personal financial reasons of a key decisionmaker. This effect may also work in the opposite direction. Since it is almost impossible to determine the impact of these incentives on the number of "dry holes, " and some external incentives are likely to continue to affect the "produce or plug" decision, the number of dry holes is taken to be those which presently are not in actual production regardless of the basis for the decision.

Ibsen-le of th, wells with negative ATNPV values in tables 8-11 would nevertheless be producers because drilling costs are already committed and the returns on incremental out-of-pocket completion, stimulation and production costs are adequate to induce production. But these wells would not return 10 percent after taxes on total Investment.

As evident from table 7 there is great variability among the localities in the share of dry-hole costs for each producing well. This variability does not arise solely from the actual costs of a dry hole as shown in column 1, but rather in the ratio of number of dry holes to the number of producing wells in each locality. This

Table 7
Effect of Dry Holes on the Cost of Producing Wells

(Dollars in thousands, 1976 constant)

Locality	Column 1 Cost of a Dry Hole	Column 2 Cost of Dry Hole-Net of Tax Writeoff*	Column 3 No. of Dry Holes	Column 4 No, of Producing Wells	Column 5 Share of After-Tax Dry-Hole Cost for Each Producing Well
High Quality.	$ 86.9	$34.7	15	72	$7.2
Medium Quality					
Frac	97.9	29.6	1	27	1.5
Shot.	96.1	38.4	1	150	0.3
Lower Quality	101.1	40.4	49	241	8.2

● This calculation is based on a 48 percent marginal Federal tax rate and a 12 percent average State tax rate. It also is based on the assumption that the taxpayer has at least this much income which would otherwise be taxable at these rates. To the extent the taxpayer is not at the marginal Federal and State tax rates, the average State tax rate is less than 12 percent, or the taxpayer does not have income which would otherwise be taxable, the after-tax cost of dry holes increases heterogeneity probably arises not just from geologic differences but also from the operators' aggressiveness in drilling to the boundaries of the resource pool. The values of table 7 are included as negative components of the ATNPV calculations reported in tables 8 through 11.

Analytical Results for After-Tax Net-Present Values Under Alternative Price and Tax Assumptions

The basic analytical results are presented in tables 8 through 11. In each table, the four alternative price assumptions are the column headings. The resource quality examples are the row headings. For the medium-quality resource base example, two alternative stimulation techniques are displayed. For the lower-quality resource base example, two stimulation techniques and two internal quality distinctions are displayed. Each table refers to a specific tax case:

- Table 8; depletion allowance = zero, investment tax credit = zero,
- Table 9; depletion allowance = 22 percent, investment tax credit = zero,
- Table 10; depletion allowance = zero, investment tax credit = 10 percent,
- Table 11; depletion allowance = 22 percent, investment tax credit = 10 percent.

The entries in the bodies of the tables are the after-tax net-present values (ATNPV; in thousands of dollars) based on the actual investment and operating costs and production profiles in the three localities under the assumed price and tax conditions and at a 10-percent discount factor. if the entry is positive, the investment has an internal rate of return in excess of 10 percent. If the entry is negative, the investment has an internal rate of return of less than 10 percent.

For example, in table 8 (depletion and investment tax credit both equal to zero), only the high-quality resource has a calculated ATNPV per well which is positive at an assumed price of $1.42 per Mcf. All the other situations have per-well ATNPVs which are negative. This may appear anomalous because the actual localities upon which these illustrative ATNPV calculations are based are all being developed. [17] This continuing development is presumably based on private business decisions involving expectations of positive after-tax net present values. The fact that

[17] It will be recalled that the high-quality case is based on operating experience in the Cottageville, W. Va., area; the medium-quality case on Clendenin, W. Va.; and the lower-quality case on Perry County, Ky.

Table 8
After-Tax Net-Present Value of Brown Shale Natural Gas Wells in Three Locations-Case A*

(Dollars in Thousands, 1976 constant)

Location	Stimulation	Wellhead Price per Mcf			
		$1.42	$2.00	'$2.50	$3.00
High Quality	Shot	+21	+57	+84	+114
Medium Quality	Frac	–16	+10	+33	+56
	Shot	–19	–1	+13	+28
Lower Quality					
Good	Frac	–16	+13	+38	+63
Good	Shot	–22	– 3	+13	+28
Bad	Frac	–55	–42	–31	–20
Bad	Shot	–48	–40	–32	–25

"Assumptions:

Depletion Allowance	0
Investment Tax Credit	0

Table 9
After-Tax Net-Present Value of Brown Shale Natural Gas Wells in Three Locations-Case B*

(Dollars in Thousands, 1976 constant)

Location	Stimulation	Wellhead Price per Mcf $1.42	$2.00	$2.50	$.3.00
High Quality	Shot	+43	+86	+123	+160
Medium Quality	Frac	+1	+34	+63	+91
	Shot	–8	+14	+33	+51
Lower Quality					
Good	Frac	+2	+39	+70	+102
Good	Shot	–lo	+14	+35	+52
Bad	Frac	–50	–31	–17	–3
Bad	Shot	–45	–33	–23	–13

● **Asumptlons:**
Depletion Allowance **220/0**
Investment Tax Credit 0

Table 10
After-Tax Net-Present Value of Brown Shale Natural Gas Wells in Three Locations-Case C*

(Dollars in Thousands, 1976 constant)

Locations	Stimulation	Wellhead Price per Mcf $1.42	$2.00	$2.50	$3.00
High Quality . . . .“.	Shot	+23 “	+57	+86	+116
Medium Quality	Frac	–13	+13	+36	+59
	Shot	–17	0	+15	+30
Lower Quality					
Good.	Frac	–13	+16	+41	+66
Good	Shot	–20	– 1	+15	+32
Bad ., ...	Frac	–52	–39	–28	–17
Bad , ...	Shot	–46	–38	–30	–23

“Assumption:
Depletion Allowance 0
Investment Tax Credit **10“/0**

Table 11
After-Tax Net-Present Value of Brown Shale Natural Gas' Wells in Three Locations-Case D*

(Dollars in Thousands, *1976* constant)

Location	Stimulation	Wellhead Price per Mcf $1 .42	$2.00	$2.50	$3.00
High Quality	Shot	+45	+37	+125	+162
Medium Quality	Frac	+4	+37	+66	+94
	Shot	–6	+16	+34	+53
Lower Quality					
Good	Frac	+6	+42	+74	+105
Good	Shot	–8	+16	+37	+58
Bad	Frac	–46	–28	–13	+1
Bad	Shot	–43	–31	–21	–11

● **Assumption:**

Depletion Allowance 220/0
Investment Tax Credit 10"/0

the lower-limit base case has negative ATNPVS for most situations is attributable to a number of factors:

- there is no Btu adjustment in the assumed prices;
- some of the gas is sold in intrastate markets at higher prices;
- the assumed tax treatment is more severe than that actually experienced by many operators;
- the assumptions concerning investment and operating costs and well lives were generally slightly tilted in the direction of adverse results; and
- the poorer situations in the lower-quality resource area are legitimate losers. " "

The lower-limit base case for $1.42 per Mcf in table 8 reflects the conservative nature of the assumptions on which the ATNPV calculations are based in all the price and tax cases analyzed.

The particular ATNPV figures reported in tables 8 through 11 are all of interest,[18] but what is of special interest is the general pattern of results. As the wellhead price of gas increases from $1.42 per Mcf to $2.00 per Mcf, it becomes economically feasible to produce shale gas from some of the medium- and lower-quality sites of the gas-productive area. The price change of $1.42 per Mcf to $2.00 per Mcf appears to have a greater effect on making shale locations economically feasible than does the change from $2.00 to $2.50 per Mcf, or a change from $2.50 to $3.00 per Mcf.

For example, in table 8, under the most severe tax assumptions, at an assumed price of $2.00 per Mcf, the pattern of ATNPV results is such that the high-quality resource area is a prime candidate for development, the medium-quality resource area is marginally attractive, and the best situation in the lower-quality resource area is economically rewarding. At $2.50 per Mcf, both situations in the medium-quality area become economically attractive and the good locations in the lower-quality area have a positive ATNPV. Because the areal extent of each of these gas-productive quality areas is not known, the actual impact on potential production cannot be determined.

It is instructive to compare table 8 with table 11. Table 8 is the most severe tax case examined. Table 11 is the most liberal (in terms of the

[18]If economic incentives are such that there is substantial Devonian shale development under conditions of positive ATNPV per well, it can be expected that royalty payments, lease bonuses, and lease rentals will absorb the major portion of the difference between prospective expected wellhead prices and costs.

generosity with which income from gas production is treated) tax case examined. At $2.00 per Mcf, two additional situations achieve positive ATNPV values in table 11 which did not achieve positive ATNPV values in table 8. These are shot wells in the medium-quality resource area and shot wells in the good area in the lower-quality resource area. Note that the liberal tax treatment does not increase the area of potential gas production, but does make shot wells economically feasible in the medium- and lower-quality good areas. A well head price of $2.50 per Mcf does not increase the potentially productive area of the shale resource but it does increase the value of the wells and, like the $2.00 price, makes shot wells economically feasible. A wellhead price of $3.00 per Mcf under the most liberal tax treatment makes shale gas production from all three localities in the gas-productive area economically feasible.

A comparison of data in table 8 with that in table 9 shows that a 10-percent investment tax credit would have little positive impact on shale gas development. However, a comparison of data in table 8 with that in table 10 shows the positive impact of a 22-percent depletion allowance. At $1.42 per Mcf, in addition to increasing the value of wells in the high-quality locations, a 22-percent depletion allowance makes hydrofractured wells in the medium- and lower-quality good areas economically feasible. Basically, the 22-percent depletion allowance has about the same positive effect as a $.50 per Mcf increase in wellhead price.

Extent of the Economically Producible Area

As indicated in an earlier section, estimates of the natural gas in the Brown shale are subject to great variability. The question involves not only the total resource present but also the portion that can be economically produced. Until the Brown shale resource of the Appalachian Basin is more fully characterized, there will continue to be great uncertainty in any attempt to estimate the extent of the Appalachian Basin which might sustain commercial development of shale gas production.

The ATNPV analyses indicate that under many of the price and tax scenarios, drilling for and producing shale gas from localities in the known shale gas productive area is economically feasible. However, it is unrealistic to assume that the current gas-productive area is representative of the whole Appalachian Basin. A number of general observations about resource deposits are relevant. First, the distribution of resource deposits in nature tend to be highly skewed, i.e., there are fewer very high-quality resource deposits than medium-quality deposits, and fewer medium-quality deposits than low-quality deposits.[19,20] Second, the better-quality resources tend to be developed first.[21] There being no strong evidence to the contrary, OTA assumes that these principles apply to gas-bearing shales of the Appalachian Basin.

In a marginal resource base such as the Brown shale, the definition of "better-quality resource" includes, as a determinant, location relative to existing production and pipelines. Until recently, the Brown shale have not been a primary target of drilling except in the Big Sandy area. The current areas of shale development were initially

[19] J. W. McKie, "Market Structure and Uncertainty in Oil and Gas Exploration," Quarterly *Journal of Economics,* Vol. 74, pp. 543-571, November, 1960.

[20] G. Kaufman, "Statistical Decision and Related Techniques in Oil and Gas Exploration," Prentice Hall, Englewood Cliffs, N. J., 1973, and J. Aitchison and J. A. C. Brown, "The Lognormal Distribution," Cambridge University Press, New York, N. Y., 1957.

[21] G. Kaufman, Y. Bulcer, and D. Kryt. "A Probabilistic Model of Oil and Gas Discovery," *Studies in Geology,* Vol. *1,* American Association of Petroleum Geologists, *Tulsa, Okla,* pp. 113-142, 1975.

byproducts of other activity. While it might appear that this fact would blunt the operation of the principle that the better prospects are drilled first, this is not the case. Even if the initial knowledge of Brown shale prospects was developed as a byproduct of other activity, the better Brown shale prospects (byproducts or not) are developed first. "Better" here, however, involves a strong element of location relative to existing pipelines. This is particularly true for historical wellhead price levels. Evidence of this is that much of the Brown shale production in West Virginia is served by existing interstate pipelines.

All of this suggests that there may be other areas which are geologically as promising as the three localities examined here. These other areas, although more remote relative to existing pipelines, may become economically feasible at the $2.00 to $3.00 per Mcf price levels examined in the sensitivity analysis reported herein.

There might be a temptation to extrapolate the production results from the three sample locations in the currently productive, area directly to the entire Appalachian Basin. Results of such an extrapolation are not likely to be valid primarily because:

- the existing wells are not located randomly in the Appalachian Basin, but rather are clustered in a known producing area;
- the gas-productive area sampled (98.6 square miles) is less than 0.06 percent of the 163,000-square-mile Appalachian Basin;
- the 490 sample wells are but a very small (5 percent) portion of the 10,000 producing wells in the Appalachian Basin, and do not represent a random sample; and
- average production data from producing wells are biased because dry holes and plugged and abandoned wells are not included in the "average production."

OTA assumed that the production potential in the currently producing area is much higher than is characteristic of the Appalachian Basin as a whole.

Based on the following information, OTA estimates that about 10 percent of the 163,000-square-mile extent of the Appalachian Basin might be of high enough quality to produce shale gas economically at a price of $2.00 to $3.00 per Mcf.

1. *Production History.*—The wells which have a potential of producing more than 240 to 300 Mcf of shale gas over a 15- to 20-year period tend to be clustered in a few locations in the Appalachian Basin. This type of distribution of commercially productive wells indicates that not all of the Appalachian Basin is composed of the same resource quality. No doubt additional locations exist which have commercial potential, but it is unlikely that these areas will comprise a significant portion of the 163,000-square-mile extent of the Appalachian Basin.

2. *Shale Depth.*—The Brown shale outcrops at the surface in central Ohio and is 12,000 feet below the surface in northeastern Pennsylvania. Because drilling and stimulation costs increase with depth, commercial production of shale gas in the volumes encountered in the best wells to date is generally limited to depths less than 5,000 feet. A considerable extent of the Brown shale of the Appalachian Basin is deeper than 5,000 feet and is therefore unlikely to sustain commercial shale gas production under the economic conditions and technology considered in this assessment.

3. *Shale Thickness.*—The total thickness of the gas-productive Brown shale sequence in the Devonian rocks varies from less than 100 feet to more than 1,000 feet across the Appalachian Basin (figure 3). It is not generally economical to stimulate Brown shale layers which are less than 100 feet in thickness unless multiple layers in one well can be treated. The Brown shale resource in a significant portion of the Appalachian Basin consists of thin layers of Brown shale which may not be amenable to modern hydrofracture techniques.

4 *Fractures.—The* fracture system (number, length, openness, and direction of fractures or joints) in the Brown shale is not uniform across the Appalachian Basin. The much-fractured areas of the Brown shale tend to be more gas-productive than the less-fractured areas. Extensive areas of the Appalachian Basin have limited fracture systems and therefore are potentially poorer areas for shale gas production even with modern stimulation techniques than the much-fractured areas.

5 *Drilling* Experience. -Drilling and production records of independent operators in the Appalachian Basin have reflected vast areas where shale gas production is uneconomic unless new stimulation techniques can more than double shale gas production rates without significant increases in cost. Poor shale gas production experience over extensive areas probably is a result of a combination of the circumstances outlined above.

An Estimate of Readily Recoverable Reserves

The Appalachian Basin has an areal extent of about 163,000 square miles. If 10 percent of this area is of high enough quality to be economically attractive for shale gas production at prices of $2.00 to $3.00 per Mcf, it provides a potential production area of 16,300 square miles. (The present gas-productive area is less than 5 percent of the 163,000-square-mile area.) With a spacing of 150 acres per well, this area would support approximately 69,000 wells. Production data presented in table 4 show that wells economically feasible at **$2.00** per Mcf will produce approximately 240 million cubic feet of shale gas per well over a 15-year period, and about 290 million cubic feet per well over 20 years.[22] Readily recoverable reserves were determined by multiplying the number of potential wells by the average production per well as follows:

15-year *readily recoverable reserve*
69,000 wells x 240 MMcf/well = 16.6 Tcf

20-year readily recoverable reserve
69,000 wells x 290 MMcf/well = 20.0 Tcf

If the entire undeveloped gas-productive area were a medium-quality resource and all wells were shot treated, the 15-year readily recoverable reserve would be 9 Tcf; use of hydrofracturing rather than shot treatment would increase this figure to 15 Tcf. The 20-year readily recoverable reserves would approximate 11 and 19 Tcf, respectively. If 10 percent of the 163,000-square-mile (1 6,300 square miles) gas-productive area were all high-quality resource and all wells were shot treated, the readily recoverable reserve would be about 17 Tcf over a 15-year period and about 20 Tcf over a 20-year period. Assuming that hydrofracturing results in a 50-percent increase in shale gas production (as is suggested by production data in table 4), 69,000 hydrofractured wells on high-quality Brown shale sites might produce 26 Tcf of gas over a 15-year period, and approximately 30 Tcf over a 20-year period.

It is highly unlikely that all of the undeveloped gas-productive Brown shale resource will be high quality, and also unlikely that all of it will be medium or low quality. For this reason, a 15 to 25 Tct estimate of readily recoverable shale gas reserves appears justified until the Brown shale resource base is more thoroughly characterized. This range clearly indicates that the Brown shale do in fact have a potential for making a significant contribution to the U.S. natural gas supply.

Because of the great uncertainty in the quality distribution of the shale resource, no attempt was made to undertake price elasticity studies in this assessment. The impact of a specific price change on shale gas production will be impossible to assess accurately until extensive resource characterization studies are completed, This will require a large amount of drilling throughout the region.

[22] In a similar analysis for a smaller producing area, ultimate recoverable reserves were used at levels of 300, 350, and 400 MMcf per well, P. J. Brown, "Energy From Shale—A Little Used Natural Resource. " Natural Gas *From Unconventional Geologic Sources,* National Academy of Sciences, J 976.

Some estimates of the total amount of gas-in-place in the Brown shale range in the hundreds of Tcf.[23] However, such estimates of the resource base should be distinguished from estimates of readily recoverable reserves, which represent the fraction of the total resource whose recovery is feasible under reasonable assumptions about costs, taxes, and geologic formations. OTA's 15 to 25 Tcf estimate of readily recoverable reserves is consistent with a total resource estimate of hundreds of Tcf because of the fact that under present technology the average shale well recovers only 3 to 8 percent of the calculated gas in place .24

General Observations and Findings

it appears that under plausible economic, geologic, and technological assumptions, the Brown shale of the Appalachian Basin contain as much as 15 to 25 Tcf of readily[25] recoverable natural gas. This reserve would be producible **in the first 15 to 20 years of the production profile of typical reservoirs. Because one of the characteristics of Brown shale gas production is a slow flow rate over a very long period of time, ultimate recoverable reserves** over the life of production would be greater. This 15 to 25 Tcf estimate critically depends on the price and cost assumptions used, the total extent of the Brown shale resource, and the distributions of resource quality.

The price assumptions ($2.00 to $3.00 per Mcf) realistically reflect the current opportunity value of additions to the U.S. natural gas supply and are consistent with general market conditions for both interstate and intrastate sales. Estimates of drilling, well completion, stimulation, and production costs are based on actual operating experience.

The estimate of 15 to 25 Tcf of readily recoverable reserves is based on the assumption that about 10 percent of the 163,000-square-mile Appalachian Basin has Brown shale of high enough quality to permit the production of shale gas economically at prices of $2.00 to $3.00 per Mcf.

From table 12 one sees the important role that the Brown shale could play in national natural gas supply, If annual production were at 1.0 Tcf,[26] the region would match some of the larger gas-producing States and make up almost 5 percent of current national production.

Table 12
Estimated Gross Production of Natural Gas of the five Largest Producing States, 1976

State	Gross Production (Tcf/annum)
Texas	7.7
Louisiana	7.1
Oklahoma	1.8
New Mexico	1.2
Kansas	0.8
Total U.S.	20.9

Source: Gas *Facts* 1976, American Gas Association (1977), p. 24.

The estimates presented in this report are based on the analysis of 490 producing wells in three gas-productive localities. These 490 wells were drilled by a large number of operators with different financial situations and technical capabilities. There are some data available from a smaller number of wells drilled by a single operator.[27] If these single-operator data are, in fact, representative of the potential of the Brown shale of the Appalachian Plateaus, this resource might

[23] *Natural Gas From Unconventional Geologic Sources*, p. 113, National Academy of Sciences, 1976.

[24] Ibid., p. 86.

[25] "Readily recoverable reserves" is not a category in either the American Gas Association or United States Geological Survey nomenclature. In the present context, "readily recoverable reserves" are resources which can be converted to proved reserves and actually produced in a 15- to 20-year time frame.

[26] The 1.0 Tcf is a central estimate based on the 15 to 25 Tcf range; therefore, one should keep in mind the variability associated with the point estimate.

[27] K.I. Brooks, R.M. Forrest, and W.I. Morse, 1974. "Gas Reserves in the Devoniain Shale in the Appalachian Basin the Operating Territory of the Columbia Gas System. " (Mimeographed Report in the files of Columbia Gas System Service Corporation, Columbus, Ohio.)

account for more than 1.0 Tcf per year of additional U.S. supply in the next 20 years. This larger production could result from either or both (1) greater average productivity per well, or (2) a larger resource base which would permit a greater number of wells of average productivity. However, even under an optimal combination of circumstances (1 5-percent higher average production per well and a 50-percent increase in the areal extent of the quality shale resource), only about 30 to 35 Tcf of readily recoverable reserves would be producible over 15 to 20 years. For the reasons cited previously, however, OTA considers such an optimal combination to be unlikely.

The 1.0 Tcf figure is a judgmental estimate based on the facts that: (1) much potential shale gas production is likely to spread over a wide area without immediate access to pipeline connections, and (2) a large amount of drilling is required to generate IS to 25 Tcf of readily recoverable reserves.

Based on production data from the three localities analyzed, creation of 15 to 25 Tcf of readily recoverable reserves will require drilling 69,000 wells. In 1975, 38,498 wells were drilled in the United States.[28] If drilling 69,000 wells with the Appalachian Basin Brown shale as the target pay zone were spread over 20 years, this number of new wells would average 3,450 wells per year. This drilling alone would represent a 9-percent increase in drilling activity over the total U.S. 1976 **level.** The U.S. drilling industry has shown considerable ability to respond to increased economic incentives. Between 1971 and 1975, total wells drilled increased by 45 percent (9 percent per year), from 26,532 to 38,498. Between 197l and 1975, total rotary-drilling rigs in operation increased by 70 percent (15 percent per year), from 976 to 1,660. Because Brown shale production is relatively well-intensive, and because it is likely to be scattered over extensive areas, it is prudent to assume that shale gas development will proceed at a gradual pace, possibly spreading the required drilling effort over 15 to 20 years.

The fact that potential shale gas production is likely to be scattered over extensive areas contributes to a relatively slow pace of development because of the requirement that natural gas be shipped by pipelines. This suggests that the economically feasible expansion of the gas-pipeline network required to serve new shale development and production will be on an incremental basis. This in turn suggests that location relative to potential pipeline connections (in addition to geologic promise) will continue to bean important determinant of the economic quality of shale drilling prospects. As a result, gradual development is a prudent assumption.

The magnitude of the required drilling effort does, however, have an important aspect. The drilling of 3,450 wells per year in the Appalachian Basin would be a significant addition to total U.S. drilling activity. There has been an impressive record of technological progress in the U.S. drilling industry.[29] This progress has been associated with deeper target horizons in the gulf coast and the Southwest. It is possible that a drilling effort of the magnitude required to develop Brown shale gas resources would sufficiently focus the attention of the drilling industry so that substantial technological progress in reducing shale drilling costs and improved deliverability would result. A comparison of table 6 with tables 8 through 11 indicates the potential of such progress to extend the margin of economic feasibility for Brown shale development. The possibility of improved drilling and completion technology is not included in the 15 to 25 Tcf estimate.

The comparison of table 6 with tables 8 through 11 is relevant to any technological advance which improves the ratio of productive capacity to investment cost, All Brown shale gas production is artificially stimulated through either hydrofracturing or shooting.[30] An improvement in stimulation technology would have an effect similar to that of an improvement in drilling technology. The possibility of an improvement in stimulation technology is not included in the 15 to 25 Tcf estimate.

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[28] Drilling stati sties are from the *Oil and Gas Journal*, **Review and Forecast Issues, 1972 and 1976, pp. 91 and 114.**

[29] See F.M. Fisher, op cit.

[30] It is noteworthy that hydrofracturing itself was developed in response to the post World War II Increase in U.S. crude oil prices,

If improvements in drilling or stimulation technology are developed by drilling or well-service contractors who can patent the techniques, it is possible that the socially optimal amount of effort to develop such technology will be forthcoming. But it is likely that much drilling, well stimulation, and production will be done by operators who do not have a very large share of total shale production. In addition, many technical improvements may not be readily patentable. Under these circumstances, the Congress may wish to consider the desirability of some publicly supported research and development activity directed toward improvements in shale drilling and stimulation technology.

The possible effect of either (1) dramatically improved technology, or (2) improvements in economic incentives beyond those examined here, must be considered with caution. This is because of the likelihood that the development effort which such possibilities would encourage would be working against an increasingly marginal resource base. If economic incentives were to be twice as good as those associated with current tax treatment and wellhead prices of $2.00 to $3.00 per Mcf; or, alternatively, if drilling and stimulation technology were to improve so that these operations cost only half as much as they do now, it is unlikely that twice as great a quantity of reserves would become economically feasible. This is because the additional development efforts which such economic or technological improvements would induce would be pressing further and further into the margin of poorer and poorer sites and geologic prospects. In addition, because poorer resource quality in the Brown shale is very much associated with slower flow rates per unit of ultimately recoverable reserves, the contribution to yearly output would be apt to increase relatively less than the increase in reserves. For example, on a purely illustrative basis, if a doubling of economic incentives or technical productivity were to result in a 50-percent increase in ultimate recovery, average output in the first 20 years might increase by only 25 percent.

The 15 to 25 Tcf of readily recoverable reserves and approximately 1.0 Tcf of yearly production reported here are based on the following assumptions:

- no significant changes in real drilling, well stimulation, or production costs;
- the economic and production characteristics of the three localities analyzed represent the more promising sources of natural gas from the Brown shale;
- wellhead prices for natural gas in the $2.00 to $3.00 per Mcf range;
- continuation of current tax treatment of income from natural gas production; and
- approximately 10 percent of total now undeveloped Appalachian Basin Brown shale resource is of high enough quality to permit commercial development.

It is a well-known axiom that there is no sure proof of gas or oil production potential other than the drillbit. It is possible that all of the undrilled resource potential of the Devonian shale has economic and production characteristics similar to those of the bad situations in the lower-quality resource area. In this case, there would be no incremental Brown shale gas production which would be economically feasible, at wellhead prices in the range of $2.00 to $2.50 per Mcf. This appears unlikely, given the geographic dispersion of Brown shale resources. There appears to be no practical way short of creating the economic incentives necessary to induce an extensive drilling effort, to ascertain whether the Appalachian Basin shale might actually contribute more, or less, than 5 percent of the total U.S. natural gas supply.

Table 13
Typical Well Costs (1976 Constant Dollars)
High-Quality Brown Shale Well

Cottageville Area, Jackson County, W.Va.

Total Depth-4,300 feet
Completion Method-Shooting 450 feet of Gross Pay Section

	Producing Well	Dry Hole
Intangible Costs:		
Title work	$ 300	$ 300
Stake location	300	300
Drilling permit & bond	350	350
Other legal expenses	200	200
Right-of-way expenses	100	—
Road & location costs	2,000	2,000
Hauling (all except cement)	3,500	3,500
Well logs (open hole)	3,000	3,000
Centralizers & float equipment	1,800	1,800
Cementing surface & conductor	3,500	3,500
Shooting 450 feet	5,000	—
Geologic & engineering service	2,800	1,400
Drilling 4,200 feet @ $8/ft	34,400	34,400
Rig charges	2,600	—
Install 2,000 feet flow line	1,730	—
Reclaim road & location	2,000	2,000
Subtotal	63,580	52,750
Contingency (6% of intangibles)	3,815	3,165
Management overhead (1 50/0 total well costs excluding contingency)	13,115	10,917
Total Intangibles	80,510	66,832
Tangible Costs:		
Conductor casing:		
30 feet of 13"@$l4.45/ft	430	430
500 feet of 9-5/8 ''@$9 .36/ft,	4,700	4,700
2,500 feet of 7"@$5.96/ft.	14,900	14,900
Christmas tree	1,000	—
Valves & fittings	1,000	—
2,000' of 2-3/8" flow line @$.91/ft.	1,820	—
Total Tangibles	23,850	20,030
Total Well Costs	$104,360	186,862

Table 14
Typical Well Costs (1976 Constant Dollars)
Medium-Quality Brown Shale Well

Blue Creek Area, Kanawha Co., W.Va.

Total Depth-500 feet
Completion Method-Hydrofracture (1,000 bbl)

	Producing Well	Dry Hole
Intangible Costs:		
Title work	$ 300	300
Stake location	350	350
Well permit & bond	350	350
Other legal expenses	200	200
Right-of-way expenses	100	—
Road & location costs	4,000	4,000
Hauling (all except cement & 4-1/2" casing)	3,500	3,500
Hauling 4-1 /2" casing & line	520	—
Well logs (open hole)	3,200	3,200
Centralizers & float equipment	1,800	1,800
Cementing conductor & surface	3,500	.3,500
Cementing 4-1 /2" casing	3,300	—
Hydrofrac-1,000 bbl, 60,000# sd, 75,000 cu. ft. nitrogen	9,020,	—
Perforate & CBL log	2,000	—
Tool and equipment rental	500	—
Frac tank rental (5 x 250-bbl@$l50/tank)	750	—
Pump or haul water @ 40/bbl x 1,000	400	—
Completion rig 140 hrs@ $55/hr	7,700	—
Geologic & engineering service	3,000	500
Drilling 5,000 feet @ $9/ft	45,000	45,000
Rig charges	2,600	—
Install 2,000 feet flow line	1,730	—
Reclaim road & location	2,000	2,000
Subtotal	95,820	64,700
Contingency (6°/0 of intangibles)	5,749	3,882
Management overhead (1 50/0 of total well costs excluding contingencies)	20,176	12,260
Total Intangibles	121,745	80,842
Tangible Costs:		
Conductor casing:		
30 feet of 13" @ $14.45/ft,	430	430
500 feet of 9-5/8" @ $9.36/ft	4,700	4,700
2,000 feet of 7" @ $5.96/ft	11,900	11,900
Production casing: 5000 feet of 4-1 /2" @ $3.12/ft	15,600	—
Christmas tree	1,000	—
Valves & fittings	1,000	—
2,000 feet of 2-3/8" flow line @$.91/'ft	1,820	—
Separator & tank	2,000	—
Valves & fittings, drips	235	—
Total Tangibles	38,685	17,030
Total Line & Well Costs	$160,430	97,872

Table15
Typical Well Costs (1976 Constant Dollars) Medium-Quality Brown Shale Well

Blue Creek Area, Kanawha Co., W.Va.

Total Depth-5,000 feet
Completion Method-Shooting 1,000 feet of Gross Pay Section

	Producing Well	Dry Hole
Intangible Costs:		
Title work	$ 300	$ 300
Stake location	350	350
Drilling permit & bond	350	350
Other legal expenses	200	200
Right-of-way expenses	100	—
Road & location costs	4,000	4,000
Hauling (all except cement)	3,500	3,500
Well logs (open hole)	1,500	1,500
Centralizers & float equipment	1,000	1,000
Cementing conductor & surface	3,500	3,500
Shooting 1,000 feet	10,000	—
Geologic & engineering service	3,000	1,500
Drilling 5,000 feet @$9/ft.	45,000	45,000
Rig charges	2,600	—
Install 2,000 feet of flow line	1,730	—
Reclaim road & location	2,000	2,000
Subtotal	79,150	63,200
Contingency (6°/0 of intangibles)	4,749	3,792
Management overhead (1 5°/0 of total well costs excluding contingency)	15,000	12,034
Total Intangibles	98.899	79.026
Tangibla Costs:		
Conductor casing:		
30 feet of 13“ @ $14.45/ft.	430	430
500 feet of 9-5/8 ''@$9 .36/ft.	4,700	4,700
2,000 feet of 7“@$5.96/ft.	11,900	11,900
Christmas tree	1,000	—
Valves & fittings	1,000	—
2,000 feet of 2-3/8” flow line @ $.91/ft	1,820	—
Total Tangibles	20,850	17.030
Total Well & Line Costs	$119,749	$96,056

Table 16
Typical Well Costs (1976 Constant Dollars) Lower-Quality Brown Shale Well

Hazard Area, Perry County, Eastern Kentucky

Total Depth-3,900 feet
Completion Method-Hydrofracture (1,000 bbl)

	Producing Well	Dry Hole
Intangible Costs:		
Title work	$ 400	$ 400
Stake location	350	350
Well permit & bond	350	350
Other legal expenses	300	300
Right-of -way	100	—
Road & location costs	5,500	5,500
Hauling (except 4-1 /2” cement)	3,500	3,500
Hauling 4-1 /2” & line pipe	500	—
Well logs (open hole)	3,000	3,000
Centralizers & float equipment	1,800	1,800
Cementing conductor & surface	3,500	3,500
Cementing 4-1 /2” casing	3,000	—
Hydrofrac-1,000 bbl, 60,000# sd, 75,000 cu. ft. nitrogen	9,020	—
Perforate & CBL log	2,000	—
Tool and equipment rental	500	—
Pump or haul 1,000 bbl water	400	—
Frac tank rental (5 x 250-bbl@$150)	750	—
Completion rig 140 hrs @ $55/hr	7,700	—
Install 2,000 feet of flow line	1,730	—
Geologic & engineering service	2,800	1,400
Drilling 3,900 feet @$ 10/ft.	39,000	39,000
Rig charges	2,600	—
Reclaim road & location	2,000	2,000
Subtotal	90,800	61,100
Contingency (6°/0 of intangibles)	5,448	3,666
Management overhead (1 5°/0 of total well & line costs excluding contingencies	19,621	12,705
Total Intangibles	115,869	77,471
Tangible Costs:		
Conductor casing:		
30 feet of 13“@$l4.45/ft	430	430
500 feet of 9-5/8 ''@$9 .36/ft.	4,700	4,700
3,100 feet of 7“@$5.96/ft.	18,476	18,476
Production casing: 3,900 feet of 4-1/2''@$3.l2/ft	12,168	—
Christmas tree	1,000	—
Valves & fittings, drips	1,235	—
Separator & tank	2,000	—
Total Tangibles	40,009	23,606
Total Well & Line Costs	$155,878	$101,077

Table 17
Typical Well Costs (1976 Constant Dollars)
Lower-Quality Brown Shale Well

Hazard Area, Perry County, Eastern Kentucky

Total Depth-3,900 feet
Completion Method-Shooting 450 feet of Gross Pay Section

	Producing Well	Dry Hole
Intangible Costs:		
Title work	$ 400	$ 400
Well permit & bond	350	350
Stake location.	350	350
Other legal expenses.	300	300
Right-of-way	100	—
Road & location costs	5,500	5,500
Hauling (except 4-1/2" casing & cement).	3,500	3,500
Well logs (open hole)	3,000	3,000
Centralizers & float equipment	1,800	1,800
Cementing conductor & surface .	3,500	3,500
Shooting 450 feet	5,000	—
install 2,000 feet of flow line. . . .	1,730	—
Geologic & engineering service	2,800	1,400
Drilling 3,900 feet @$10/ft.	39,000	39,000
Rig charges	5,200	—
Reclaim road & location	2,000	2,000
Subtotal.	74,530	61,100
Contingency (6% of intangibles) .	4,472	3,666
Management overhead (1 50/0 of total well & line costs excluding contingencies)	15,293	12,705
Total Intangibles	94,295	77.471
Tangible Costs:		
Conductor casing:		
30 feet of 13"@$l4.45/ft ., . .	430	430
500 feet of 9-5/8 ''@$9 .36/ft. .	4,700	4,700
3,100 feet of 7"@$5.96/ft. . . .	18,476	18,476
Christmas tree.	1,000	—
Valves & fittings.	1,000	—
2,000 feet of 2-3/8" flow line @$.91/ft	1,820	—
Total Tangibles	27,426	23,606
Total Well & Line Costs .	$121,721	$101,077

VII. Barriers to Brown Shale Gas Production

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Obstacles to gas production from the Brown shale are of two types: (1) barriers to immediate development of Brown shale reserves using available drilling and completion techniques; and (2) barriers to future production using improved reservoir analysis techniques, drilling methodology, and completion practices. While these two aspects are treated separately in this assessment, they are interrelated.

Obstacles to Development Using Available Technology

The major barrier to increasing production using available technology is the present controlled level of the interstate wellhead price of gas. Gas production is economically feasible (greater than a 10-percent rate of return on investment) only in the very high-quality areas of Brown shale under current controlled price levels. Current development of the Brown shale is, therefore, limited to seeking out the very high-quality areas of Brown shale. With this restriction, a significant expansion of exploration and development activity in the Appalachian Basin is unlikely.

Following a recent increase in prices for new interstate gas (*$.52* per Mcf to $1.42 per Mcf), there was a noticeable increase in drilling activity in the higher-quality Brown shale of the Appalachian Basin.

Development of the Brown shale using available technology is also hindered by problems associated with high local drilling costs, difficulties in lease acquisition, and title clearance. Drilling costs are substantially higher in southwestern West Virginia and eastern Kentucky because of the rugged terrain and poor roads, which make equipment movement difficult and expensive and increase the costs of installing gas gathering and distribution systems.

Areas with multiple minable coal seams require additional casing for each coal seam which, in turn, increases drilling rates per foot and tangible expenses for casing for wells that penetrate coal seams. The problems associated with drilling through minable coal seams will increase in the future due to the increased value of coal, and more intensive exploration and development efforts by coal operators. Additionally, leasing and purchasing of coal mining rights by investors far removed from the site will result in delays in acquiring approval to drill through coal seams. To gain approval to drill through a coal seam, a plat of the drill-site location must be submitted to the operator holding the mining rights on the potential drill-site property. If a drill site is approved by the coal operator, that operator must agree to leave a pillar of coal around the drill hole to provide an unbroken well bore through the seam. This procedure results in a loss of recoverable **coal. If, in areas of low- to medium-quality Brown shale, minable coal seams are numerous and thick, the amount of coal left as pillars around the well bore may have a greater value than the potential gas from the proposed well and, therefore, the coal operator** will refuse to permit a gas well to be drilled through the coal seams.

Brown shale areas are notorious for property and title problems. For example, in eastern Kentucky tax maps are nonexistent, courthouse records are poor, and many of the mountain people living on the land have no knowledge of the mineral ownership. problems in leasing and title clearance in such areas can be time consuming and expensive. It is not unusual to invest 6 months to 1 year to locate owners and clear the title for a potential drilling site on the Appalachian Plateaus.

Environmental constraints do not pose serious deterrents to Brown shale development. Fluids produced from wells must be contained by on-site tanks to prevent stream pollution, all pits are required to be closed, disturbed land must be reseeded, and surface erosion from access roads and the drilling site must be controlled by drainage ditches. Recent legislation imposing stringent controls on potential stream pollution and land degradation has increased drilling costs by $2,000 to $5,000 per well. This increase in well cost is minimal, representing between 1 and 4 percent of the cost of drilling and completing a typical gas well in the Brown shale.

Shortages of drilling and well-completion rigs could pose a temporary constraint on development of gas production from the Brown shale of the Appalachian Basin, Currently, there are about 73 rigs in the Appalachian area capable of drilling shale wells. ' After a well is drilled, rigs are needed to stimulate and clean out the shale wells; about 65 to 75 such completion rigs are available in the Appalachian Basin.[2] A modern drilling rig can drill about two shale wells per week, and stimulation rigs can complete about one shale well every 10 days. Under favorable conditions, the 73 drillings rigs could drill about 7,600 holes per year and about 2,400 to 2,700 of these could be brought into production by the 65 to 75 completion rigs. Therefore, even if all of the rigs currently in the Appalachian Basin were used exclusively to drill and complete new shale wells, it would not be possible to develop enough wells (69,000) to produce 1.0 Tcf per year of shale gas over the next 20 years, Favorable economics could possibly overcome the drilling and completion rig constraint over a 3 to 5 year period.

Obstacles to Advances in Shale Gas Technology

An important barrier to advances in Brown shale gas production technology is the lack of resource characterization. Even though approximately 10,000 wells produce gas from the Brown shale, very few quantitative data are available to adequately characterize the resource. Only a few of the 10,000 wells in the Brown shale have core samples available for examination, and those that do come from a relatively small portion of the 163,000-square-mile extent of the Appalachian Basin. Until the Brown shale resource is adequately characterized, focusing on specific targets for technology development is very difficult. Lack of specific research targets could result in haphazard hit-and-miss and trial-and-error experimentation with only limited chance of significant success in the near future. Detailed chemical-petrophysical data are needed for the Brown shale before significant progress can be expected in technology capable of releasing gas from those shales. Additionally, basic research is required to determine the manner in which gas is held by the Brown shale, i.e., is it only in the fractures, in the pores, adsorbed on the shale surface, or contained within the matrix porosity?

Characterization of the Brown shale involving shale petrography, core analysis work, geochemical research, and other pertinent data collection by different people in separate localities and agencies must be carefully coordinated to be effective.

Resource characterization is the initial and most pressing step for advancing technology for the purpose of increasing gas production from the Brown shale. Without an intimate knowledge of what the resource is, it is almost impossible to

[1]Information from: S.6. Plammer, Hughes Tools NE Area Regional Manager Pittsburgh, Pa; Frank Whyte, Drilling Manager, Delta Drilling Company, Indiana, Pa; James Willitt, Vice President, S.W. Jack Drilling Company, Buckhannon, W.Va.; John William, Vice President, Union Drilling Co., Buckhannon, W.Va.; John Foster, Production Eng, Columbia Gas Trans. Co, Charleston, W.Va.; James Ray, Ray Resources, Inc, Charleston, W.Va.; Roy Hancock, Petroleum Information, Charleston, W.Va.; James Burgin, President Gaspro Inc., Cambridge, Ohio; and Don Cayton, President, Central Well Service, Parkersburg, W.Va.

[2]Ibid.

program research efforts in stimulation technology, logging methods, or any of the various satellite research needs dependent on reservoir characterization.

In the past, efforts to produce gas from the Brown shale have used every conceivable stimulation method known to man; however, it has been impossible to evaluate the effectiveness of various techniques because basic reservoir characteristics have not been adequately documented. If more than 15 **to** *25* Tcf of gas is to become available from the Brown shale, -research programs must be aggressive, coordinated, and innovative.

VIII. Policy Options To Encourage Shale Gas Production

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Policy options available to encourage production of gas from the Brown shale fall into four generic categories. These categories are:

- price incentives,
- tax policies,
- research and development funding, and
- information collection and d insemination.

Price Policies

Brown shale natural gas resource development is sensitive to price. The price of Brown shale gas sold in interstate commerce is currently restricted by Federal Power Commission (FPC) ceiling price regulation. There are three basic price strategies with respect to shale gas which could be pursued. These are:

- exempt shale gas from FPC price control or establish higher prices for gas from the Brown shale;
- deregulate the wellhead price of all new natural gas supplies; or
- take no action,

A policy which permits higher prices or exempts Brown shale gas from FPC control would be analogous to a proposed policy to permit a free-market price for oil produced with enhanced recovery methods. The qualification for gas from Brown shale might be based on (1) geologic identification of the Brown shale as the source of gas, (2) regional specification, (3) production rate limitations, or some combination of these factors.

Brown shale gas production is often commingled with production from other geologic zones. Therefore, a precise identification of gas production from the Brown shale could be extremely difficult.

Because similar appearing gas-productive shales extend throughout many portions of the United States in addition to the Appalachian Basin, a regional specification restricted to the Appalachian Plateaus might omit substantial shale gas resource potential. Production rate limitations for eligibility for exemption from price regulation might be more manageable, and also would apply to gas production from tight formations in other parts of the country. Definition and administration of a multitiered pricing system for gas from the Brown shale probably would become arbitrary, complex, and cumbersome.

Deregulation of the wellhead price of all new gas supplies would include prospective additions to the U.S. natural gas supply from the Brown shale of the Appalachian Basin. Such a strategy would create price incentives in the range ($2.00 to $3.00 per Mcf) on which the analyses presented in this report are based. Such price incentives might provide the stimulus necessary for an extensive testing of the economic feasibility of Brown shale gas production. An expansion in drilling efforts could result in approximately 1.0 Tcf per year of gas from the Brown shale of the Appalachian Basin.

For Congress to take no action on prices would mean that existing prices would be the only incentive to encourage gas production from Brown shale. Current maximum interstate gas prices encourage gas production from only the high-quality Brown shale areas. Therefore, continuation of present gas-pricing policy could result in foregoing substantial additions to the U.S. natural gas supply which may be available from the Brown shale of the Appalachian Basin.

Tax Policies

The tax policies available to Congress to encourage Brown shale gas production include:

- restoration of the general percentage depletion allowances;
- definition of Brown shale gas production as enhanced recovery so as to maintain the depletion allowance for small producers;
- retention of expensing of intangible drilling costs as a tax option; and
- creation of an investment tax credit for the Brown shale.

The analysis reported here indicates that a 10-percent investment tax credit has little effect on shale gas production. Areas of lower resource quality did not become economically feasible for shale gas production when a 10-percent investment tax credit was incorporated into the analysis. However, the addition of a 22-percent depletion allowance increased the after-tax net-present value of shale wells and made shot-treated wells economically feasible in shales of lower quality. Basically, a 22-percent depletion allowance has about the same positive effect on the economics of shale gas production as a $.50 per Mcf increase in the wellhead price of shale gas.

Research and Development

There are several areas in which research and development with special relevance to the Brown shale of the Appalachian Basin might be fruitfully pursued. These include:

- defining resource characteristics;
- development of drilling techniques and equipment; and
- improvement of stimulation techniques.

Even though about 10,000 wells produce gas from the Brown shale of the Appalachian Basin, few quantitative data are available to characterize adequately the resource potential of the 163,000-square-mile Appalachian Plateaus. Until the Brown shale resource is adequately characterized, specific targets for technology development are not possible. A systematic, coordinated inventory of the Brown shale should be one of the first steps in determining the gas potential of the Brown shale sequence.

The most common techniques used to characterize the Brown shale are those developed for traditional oil and gas reservoirs. Development of special drilling techniques and equipment specifically for use in the Brown shale could expedite the development of its gas potential. Because of the importance of well stimulation in the production of gas from the Brown shale, improvement in the effectiveness and reduction in cost of stimulation techniques could make gas production more economically attractive. Price incentives can be expected to induce some private activity in these research and development areas. However, because much drilling, well stimulation, and production will be done by operators who do not control large shares of Brown shale resources, it is unlikely that those operators will invest large amounts in aggressive research and development programs. Therefore, it appears prudent to commit public funds for research and development activity directed specifically toward improvements in shale drilling and stimulation technology.

Information Collection and Dissemination

Although the Devonian shale is a geologic sequence distributed over a wide geographic area, only a small portion of it, the Brown shale, appears to have potential as a commercial source of gas. If the gas potential of the Brown shale is exploited, a large number of independent operators are likely to be drilling a large number of wells in many different locations on the Appalachian Plateaus. Under these conditions, particularly in the early years of the development effort, it might be desirable to provide public funding for the collection, coordination, and dissemination of information and analyses detailing the results of actual operating experiences. This activity should be undertaken by a creditable public group so that the results are available to the public and private sectors alike, The information collection and dissemination efforts might include public funding for conferences where research and development results and improved drilling and stimulation technologies are reported. If the Brown shale has a potential to produce 1.0 Tcf of gas per year, and economic incentives are provided, it is likely that private enterprise will assume necessary research and development efforts within a comparatively short period of time.

Conclusion

There are a number of policy options available which could encourage production of gas from the Brown shale of the Appalachian Basin. A significant and substantial policy option is to permit free market prices for gas from Brown shale sequences. Restoration of the 22-percent depletion allowance would have the same effect as increasing the wellhead price of shale gas by $.50 per Mcf. Research and development programs which characterize the Brown shale resource, decrease the cost of drilling and stimulation of wells, and increase the gas production from wells could increase the economic attractiveness of producing gas from the Brown shale of the Appalachian Basin.

IX. Summary and Conclusions

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Dark-colored shales of Devonian age (termed Brown shale) which are present beneath the Appalachian Basin are known to contain large amounts of natural gas. Gas production from the shale is greatest from much-fractured zones; initial production from Brown shale wells is relatively high, but while the rate decreases steadily the life of production is normally 15 to *50* years. Estimates of the total amount of gas in the Brown shale of the Appalachian Basin range up to many hundreds of Tcf.

It appears that gas production from Brown shale can be increased using existing technology. The recoverable gas potential of the Brown shale depends on the (1) wellhead price and production costs and; (2) extent of the commercially producible Brown shale resource. It is likely that the Brown shale of the Appalachian Basin contains as much as 15 to 25 Tcf of gas readily recoverable in 15 to 20 years at wellhead prices of $2.00 to $3.00 per Mcf. Production of gas from the Brown shale will come from many wells producing at low rates scattered over extensive areas, thus resulting in a relatively slow pace of development, Construction of pipeline gathering systems coupled with the need to drill a great number of wells in the Appalachian Basin will retard the rapid development of Brown shale gas even if adequate economic incentives are made available. **It** is prudent to expect that development of a 1.0 Tcf per year production potential will require at least 15 to 20 years. Improvements in drilling and stimulation technology and economic incentives could reduce the timelag.

Available policies which could encourage the development of shale gas production include:

1. Price or tax incentives for gas from the Brown shale;
2. Expanded research and development to define the resource and, develop more efficient drilling and stimulation technology; and,
3. Collection and dissemination of results of research, development, and actual field operating experience.

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